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Reactor Processes in Synthetic Organic Chemical Manufacturing
Industry. Background Information for Proposed Standards

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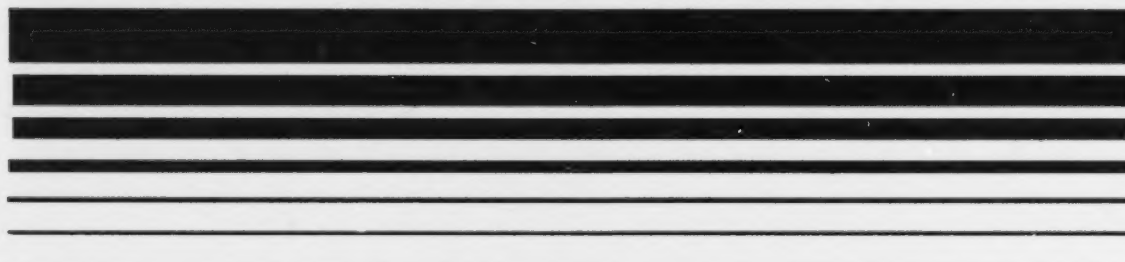
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16. ABSTRACT Standards of performance for the control of volatile organic compound (VOC) emissions from new, modified, and reconstructed reactor process units used in the manufacture of synthetic organic chemicals are being proposed under Section 111 of the Clean Air Act. This document contains background information on the industry and processes concerned and environmental and economic impact assessments of the regulatory alternatives considered in developing the proposed standards.		
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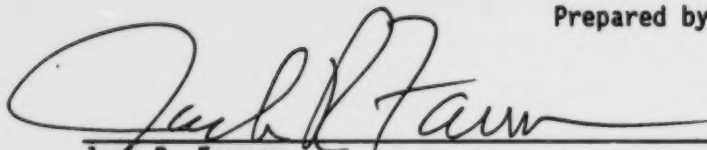
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U.S. ENVIRONMENTAL PROTECTION AGENCY
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ENVIRONMENTAL PROTECTION AGENCY

Background Information
and Environmental Impact Statement
for Volatile Organic Compound Emissions from
Reactor Processes in
Synthetic Organic Chemical Manufacturing

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1. The proposed standards of performance will limit emissions of volatile organic compounds from new, modified, and reconstructed reactor processes. Section 111 of the Clean Air Act (42 U. S. C. 7411), as amended, directs the Administrator to establish standards of performance for any category of new stationary source of air pollution that "... causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."
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1. SUMMARY

New source performance standards (NSPS) are being developed for the synthetic organic chemical manufacturing industry under authority of Section 111 of the Clean Air Act, as amended 1977. Emissions of volatile organic compounds (VOC) from various sources in this source category are being considered under several standards development programs. This background information document supports the development of NSPS for VOC emissions from reactor processes used to manufacture synthetic organic chemicals. The list of chemicals considered in this document is presented in Appendix E.

1.1 REGULATORY ALTERNATIVES

Reactor VOC emissions include all VOC in process vent streams from reactors and process product recovery systems. Not included in process equipment are product purification devices involving distillation operations. Two broad categories of reactor processes are liquid phase reactions and gas phase reactions. Four potential atmospheric emission points include: direct reactor process vents from liquid phase reactors, vents from product recovery devices applied to vent streams from liquid phase reactors, vents from gas phase reactors after either the primary or secondary product recovery device, and exhaust gases from combustion devices applied to any of these streams. Some chemical production processes may have no reactor process vent to the atmosphere, while others may have one or more vent streams.

There are numerous control techniques applicable to the reduction of VOC emissions from reactor processes. Some of these techniques are used primarily for product recovery; these techniques include condensation, carbon adsorption, and gas absorption. Product recovery device performance varies with stream characteristics, and as a consequence, it is not possible with available information to identify subcategories of reactor processes for which these devices would always be applicable. As a result, product recovery devices were not analyzed in the regulatory analysis.

Combustion control techniques have been demonstrated to be applicable to all reactor process vent streams and universally achieve higher VOC destruction efficiency than other demonstrated control technologies on reactor process vent streams, generally for a reasonable cost. Therefore, combustion control is selected as a candidate technology for the regulatory analysis. Combustion can be achieved in thermal incinerators, catalytic incinerators, boilers, process heaters, and flares. It is not possible to identify subcategories of reactor process vent streams for which the use of catalytic incinerators, process heaters, and boilers would always be

applicable. Therefore, these devices were not considered in the regulatory analysis. The remaining control technologies, thermal incinerators and flares, were selected for the regulatory analysis. Both incinerators and flares are capable of achieving at least 98-weight-percent VOC destruction. Flares are applied to vent streams containing nonhalogenated VOC in the regulatory analysis except when thermal incinerators are found to be less expensive. Incinerators are applied to vent streams containing halogenated VOC because flare tip corrosion may prohibit the use of flares and because halogenated streams may create levels of secondary emissions that require flue gas scrubbing (which is not possible from flared emissions). In the regulatory analysis, when incinerators are applied to vent streams containing halogenated VOC, the cost of a flue gas scrubber is included.

The regulatory analysis was based on the control of varying numbers of new, modified, and reconstructed process units that are projected to come on-line between 1985 and 1990 (the fifth year of the NSPS applicability). The projections used in the analysis were prepared from data on reactor processes tabulated in Chapter 9.

The concept of total resource effectiveness (TRE) is used to define regulatory alternatives. TRE consists of an index of cost effectiveness, where cost effectiveness is simply the annual cost of control divided by the annual emissions reduction, expressed in dollars per megagram (\$/Mg) of VOC controlled. In analyzing the regulatory alternatives, flares and incinerators were applied to the 56 reactor process units anticipated to be candidates for the addition of VOC controls over the first 5 years of the standards' applicability. The costs and TRE levels for each process unit are then calculated and analyzed.

Each regulatory alternative is constituted by a chosen cost-effectiveness cutoff level on the continuum of all possible values. Therefore, the proportion of process units controlled under each alternative varies with the cost-effectiveness cutoff level considered for the alternative. Because fewer reactor process units are controlled at lower TRE cutoff values, the range of alternatives examined results in increasing numbers of new, modified, and reconstructed reactor process units being controlled at higher cutoff values. The baseline alternative is representative of no additional combustion control applied to all of the 56 new, modified, and reconstructed process units with uncombusted vent streams. The most stringent alternative possible is representative of combustion controls applied to all 56 process units. The range of TRE values which could be examined in the regulatory analysis forms a continuum between these two extremes.

A particular TRE value can be selected to serve as a limit for requiring VOC emissions control. When used in a standard, TRE values below the limit would dictate use of VOC emissions control. Values above the limit would indicate that a higher level of control was already in place for purposes such as product recovery or that the reactor process had inherently small VOC emissions that proved extremely costly to control.

1.2 ENVIRONMENTAL IMPACTS

When applied to a given reactor vent stream, flares and incinerators can achieve 98-weight-percent destruction of VOC contained in the vent stream. Thus, the control levels achieved in the regulatory analysis ranged from the baseline control level of zero percent to the 98-weight-percent control level assuming control of all process units; these control levels correspond to a nationwide VOC emissions reduction attributable to the NSPS of zero megagram per year (Mg/yr) (at baseline) to approximately 2,300 Mg/yr (at control of all projected process units). In addition, other impacts of the regulatory alternatives (water pollution, solid waste, energy) were examined. A matrix describing the impacts of the extremes of the regulatory analysis (no control over baseline, total control) is presented in Table 1-1.

The primary environmental impact of the regulatory alternatives is the reduction of VOC emissions from reactor processes. The total VOC emissions from all new, modified, and reconstructed process units under baseline is estimated to be approximately 3,300 Mg/yr (3,600 tons/yr) in 1990. About 2,400 Mg/yr (2,600 tons/yr) of these VOC emissions are from process units with vent streams where combustion is not projected to be used at baseline; while about 910 Mg/yr (1,000 tons/yr) of these VOC emissions are emitted from the outlets of combustion devices expected to use combustion devices in the absence of an NSPS. Thus, 98 percent of 2,400 Mg/yr or approximately 2,300 Mg/yr (2,600 tons/yr) of VOC is available to be controlled under the regulatory alternatives. The most stringent alternative at which this emissions reduction would be achieved represents control of all projected reactor process units. This maximum emissions reduction accounts for about 70 percent of all baseline VOC emissions and 98 percent of all VOC emissions that are not currently controlled at the baseline control alternative. Increases in other air pollutants as a result of the VOC emissions controls examined are considered negligible. No direct solid wastes are expected to result from implementation of any of the regulatory alternatives other than negligible quantities of incinerator ash.

No increase in total facility VOC wastewater is projected due to combustion or product recovery devices. There is no organic wastewater associated with the combustion devices (flares and incinerators) considered in the regulatory analysis. Product recovery may be chosen by the facility owner or operator to reduce process vent stream emissions and, maintain a TRE index at a desired level. Any product recovery device will - by definition - recycle product, by-product, or reactant for process use, reuse, or sale. Therefore, no significant amount of organic wastewater is anticipated to be generated from these devices. Some facilities with halogenated VOC in the vent stream may have to dispose of brine solutions from incinerator flue gas scrubbers. However, few if any facilities with halogenated VOC are expected to actually control as a result of a reactor process NSPS. Thus, little, if any, salt disposal is expected to occur as a result of the standard. Available data show that most plants with halogenated VOC are already using combustion devices and many are disposing of the brine at a relatively low cost in sewers, brackish water systems, and by other methods.

The impact on the projected national energy usage depends upon the regulatory alternative considered (degree of overall control) and the control device used (flare, incinerator). For the most stringent alternative (control of all reactor process units) the national energy usage in the fifth year was estimated to be 520 terajoules per year (TJ/yr) (84,000 barrels of fuel oil equivalent/year). For these estimates, an incinerator with flue gas scrubbing was assumed to be used for halogenated vent streams, and the less expensive of a flare and an incinerator was assumed to be used for non-halogenated vent streams. Since process heaters, boilers, and product recovery upgrading will be used, the energy impacts will be smaller than the above estimates.

1.3 ECONOMIC IMPACT

The projected national costs of the regulatory alternatives depend upon the degree of control considered and the control device used. For control of all units, the projected national costs in the fifth year was estimated to be \$9.3 million/year.

A chemical price impact screening analysis (see Chapter 9 and Appendix H) indicated that all of the chemicals considered under the scope of this program would pass a 5 percent price increase criterion. Furthermore, the vast majority could pass more stringent price increase criteria.

The economic analysis indicates that there would be no significant impacts on industry structure, foreign trade, employment, growth, or capital markets.

TABLE 1-1. MATRIX OF ENVIRONMENTAL AND ECONOMIC IMPACTS FOR
THE EXTREMES OF REGULATORY ALTERNATIVES CONSIDERED

Administrative Action	Air Impact	Water Impact	Solid Waste Impact	Energy Impact	Economic Impact
No NSPS	0	0	0	0	0
Control All Units	+2	-1	0	-1 to +1	-1

Key: 0 No Impact
 1 Negligible Impact
 2 Small Impact
 3 Moderate Impact
 4 Large Impact
 + Beneficial Impact
 - Adverse Impact

2. INTRODUCTION

2.1 BACKGROUND AND AUTHORITY FOR STANDARDS

Before standards of performance are proposed as a Federal regulation, air pollution control methods available to the affected industry and the associated costs of installing and maintaining the control equipment are examined in detail. Various levels of control based on different technologies and degrees of efficiency are examined. Each potential level of control is studied by EPA as a prospective basis for a standard. The alternatives are investigated in terms of their impacts on the economics and well-being of the industry, the impacts on the national economy, and the impacts on the environment. This document summarizes the information obtained through these studies so that interested persons will be able to see the information considered by EPA in the development of the proposed standard.

Standards of performance for new stationary sources are established under Section 111 of the Clean Air Act (42 U.S.C. 7411) as amended, herein-after referred to as the Act. Section 111 directs the Administrator to establish standards of performance for any category of new stationary source of air pollution which ". . . causes, or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."

The Act requires that standards of performance for stationary sources reflect ". . . the degree of emission reduction achievable which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated for that category of sources." The standards apply only to stationary sources, the construction or modification of which commences after regulations are proposed by publication in the Federal Register.

The 1977 amendments to the Act altered or added numerous provisions that apply to the process of establishing standards of performance.

1. The EPA is required to list the categories of major stationary sources that have not already been listed and regulated under standards of performance. Regulations must be promulgated for these new categories on the following schedule:

- a. 25 percent of the listed categories by August 7, 1980.
- b. 75 percent of the listed categories by August 7, 1981.
- c. 100 percent of the listed categories by August 7, 1982.

A governor of a State may apply to the Administrator to add a category not on the list or may apply to the Administrator to have a standard of performance revised.

2. The EPA is required to review the standards of performance every 4 years, and, if appropriate, revise them.

3. The EPA is authorized to promulgate a standard based on design, equipment, work practice, or operational procedures when a standard based on emission levels is not feasible.

4. The term "standards of performance" is redefined, a new term "technological system of continuous emission reduction" is defined. The new definitions clarify that the control system must be continuous and may include a low- or nonpolluting process or operation.

5. The time between the proposal and promulgation of a standard under Section 111 of the Act may be extended to 6 months.

Standards of performance, by themselves, do not guarantee protection of health or welfare because they are not designed to achieve any specific air quality levels. Rather, they are designed to reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction, taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impacts, and energy requirements.

Congress had several reasons for including these requirements. First, standards with a degree of uniformity are needed to avoid situations where some States may attract industries by relaxing standards relative to other States. Second, stringent standards enhance the potential for long-term growth. Third, stringent standards may help achieve long-term cost savings by avoiding the need for more expensive retrofitting when pollution ceilings may be reduced in the future. Fourth, certain types of standards for coal-burning sources can adversely affect the coal market by driving up the price of low-sulfur coal or effectively excluding certain coals from the reserve base because their untreated pollution potentials are high. Congress does not intend that new source performance standards contribute to these problems. Fifth, the standard-setting process should create incentives for improved technology.

Promulgation of standards of performance does not prevent State or local agencies from adopting more stringent emission limitations for the same sources. States are free under Section 116 of the Act to establish even more stringent emission limits than those established under Section 111 or those necessary to attain or maintain the National Ambient Air Quality Standards (NAAQS) under Section 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under Section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area that falls under the prevention of

significant deterioration of air quality provisions of Part C of the Act. These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology. The term best available control technology (BAT), as defined in the Act, means

. . . an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from, or which results from, any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best available control technology" result in emissions of any pollutants which will exceed the emissions allowed by an applicable standard established pursuant to Section 111 or 112 of this Act.
(Section 169(3))

Although standards of performance are normally structured in terms of numerical emission limits where feasible, alternative approaches are sometimes necessary. In some cases physical measurement of emissions from a new source may be impractical or exorbitantly expensive. Section 111(h) provides that the Administrator may promulgate a design or equipment standard in those cases where it is not feasible to prescribe or enforce a standard of performance. For example, emissions of hydrocarbons from storage vessels for petroleum liquids are greatest during tank filling. The nature of the emissions, high concentrations for short periods during filling and low concentrations for longer periods during storage, and the configuration of storage tanks make direct emission measurement impractical. Therefore, a more practical approach to standards of performance for storage vessels has been equipment specification.

In addition, Section 111(i) authorizes the Administrator to grant waivers of compliance to permit a source to use innovative continuous emission control technology. In order to grant the waiver, the Administrator must find: (1) a substantial likelihood that the technology will produce greater emission reductions than the standards require or an equivalent reduction at lower economic, energy, or environmental cost; (2) the proposed system has not been adequately demonstrated; (3) the technology will not cause or contribute to an unreasonable risk to the public health, welfare, or safety; (4) the governor of the State where the source is located consents; and (5) the waiver will not prevent the attainment or maintenance of any ambient standard. A waiver may have conditions attached to assure the source will not prevent attainment of any NAAQS. Any such condition will have the force of a performance standard. Finally, waivers have definite end dates and may be terminated earlier if the conditions are not met or if the system fails to perform as expected.

In such a case, the source may be given up to 3 years to meet the standards with a mandatory progress schedule.

2.2 SELECTION OF CATEGORIES OF STATIONARY SOURCES

Section 111 of the Act directs the Administrator to list categories of stationary sources. The Administrator ". . . shall include a category of sources in such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Proposal and promulgation of standards of performance are to follow.

Since passage of the Clean Air Amendments of 1977, considerable attention has been given to the development of a system for assigning priorities to various source categories. The approach specifies areas of interest by considering the broad strategy of the Agency for implementing the Act. Often, these "areas" are actually pollutants emitted by stationary sources. Source categories that emit these pollutants are evaluated and ranked by a process involving such factors as: (1) the level of emission control (if any) already required by State regulations, (2) estimated levels of control that might be required from standards of performance for the source category, (3) projections of growth and replacement of existing facilities for the source category, and (4) the estimated incremental amount of air pollution that could be prevented in a preselected future year by standards of performance for the source category. Sources for which an NSPS were promulgated or under development during 1977, or earlier, were selected on these criteria.

The Act amendments of August 1977 establish specific criteria to be used in determining priorities for all major source categories not yet listed by EPA. These are: (1) the quantity of air pollutant emissions that each such category will emit, or will be designed to emit; (2) the extent to which each such pollutant may reasonably be anticipated to endanger public health or welfare; and (3) the mobility and competitive nature of each such category of sources and the consequent need for nationally applicable NSPS.

The Administrator is to promulgate standards for these categories according to the schedule referred to earlier.

In some cases it may not be feasible immediately to develop a standard for a source category with a high priority. This might happen when a program of research is needed to develop control techniques or because techniques for sampling and measuring emissions may require refinement. In the developing of standards, differences in the time required to complete the necessary investigation for different source categories must also be considered. For example, substantially more time may be necessary if numerous pollutants must be investigated from a single source category. Further, even late in the development process the schedule for completion of a standard may change. For example, inability to obtain emission data from well-controlled sources in time to pursue the development process in a

systematic fashion may force a change in scheduling. Nevertheless, priority ranking is, and will continue to be, used to establish the order in which projects are initiated and resources assigned.

After the source category has been chosen, the types of facilities within the source category to which the standard will apply must be determined. A source category may have several facilities that cause air pollution, and emissions from some of these facilities may vary from insignificant to very expensive to control. Economic studies of the source category and of applicable control technology may show that air pollution control is better served by applying standards to the more severe pollution sources. For this reason, and because there is no adequately demonstrated system for controlling emissions from certain facilities, standards often do not apply to all facilities at a source. For the same reasons, the standards may not apply to all air pollutants emitted. Thus, although a source category may be selected to be covered by a standard of performance, not all pollutants or facilities within that source category may be covered by the standards.

2.3 PROCEDURE FOR DEVELOPMENT OF STANDARDS OF PERFORMANCE

Standards of performance must: (1) realistically reflect best demonstrated control practice; (2) adequately consider the cost, the nonair quality health and environmental impacts, and the energy requirements of such control; (3) be applicable to existing sources that are modified or reconstructed as well as new installations; and (4) meet these conditions for all variations of operating conditions being considered anywhere in the country.

The objective of a program for developing standards is to identify the best technological system of continuous emission reduction that has been adequately demonstrated. The standard-setting process involves three principal phases of activity: (1) information gathering, (2) analysis of the information, and (3) development of the standard of performance.

During the information-gathering phase, industries are queried through a telephone survey, letters of inquiry, and plant visits by EPA representatives. Information is also gathered from many other sources, and a literature search is conducted. From the knowledge acquired about the industry, EPA selects certain plants at which emission tests are conducted to provide reliable data that characterize the pollutant emissions from well-controlled existing facilities.

In the second phase of a project, the information about the industry and the pollutants emitted is used in analytical studies. Hypothetical "model plants" are defined to provide a common basis for analysis. The model plant definitions, national pollutant emission data, and existing State regulations governing emissions from the source category are then used in establishing "regulatory alternatives." (For the reactor processes standard, there are a few deviations from this model plant and regulatory

analysis approach, as described in Chapters 6 through 8.) These regulatory alternatives are essentially different levels of emission control.

The EPA conducts studies to determine the impact of each regulatory alternative on the economics of the industry and on the national economy, on the environment, and on energy consumption. From several possible applicable alternatives, EPA selects the single most plausible regulatory alternative as the basis for a standard of performance for the source category under study.

In the third phase of a project, the selected regulatory alternative is translated into a standard of performance, which, in turn, is written in the form of a Federal regulation. The Federal regulation, when applied to newly constructed plants, will limit emissions to the levels indicated in the selected regulatory alternative.

As early as is practical in each standard-setting project, EPA representatives discuss the possibilities of a standard and the form it might take with members of the National Air Pollution Control Techniques Advisory Committee. Industry representatives and other interested parties also participate in these meetings.

The information acquired in the project is summarized in the background information document (BID). The BID, the standards, and a preamble explaining the standards are widely circulated to the industry being considered for control, environmental groups, other government agencies, and offices within EPA. Through this extensive review process, the points of view of expert reviewers are taken into consideration as changes are made to the documentation.

A "proposal package" is assembled and sent through the offices of the EPA Assistant Administrators for concurrence before the proposed standard is officially endorsed by the EPA Administrator. After being approved by the EPA Administrator, the preamble and the proposed regulation are published in the Federal Register.

As a part of the Federal Register announcement of the proposed regulation, the public is invited to participate in the standard-setting process. The EPA invites written comments on the proposal and also holds a public hearing to discuss the proposed standard with interested parties. All public comments are summarized and incorporated into a second volume of the BID. All information reviewed and generated in studies in support of the standard of performance is available to the public in a "docket" on file in Washington, D.C.

Comments from the public are evaluated, and the standard of performance may be altered in response to the comments.

The significant comments and the EPA's position on the issues raised are included in the "preamble" of a promulgation package, which also contains the draft of the final regulation. The regulation is then subjected to another round of review and refinement until it is approved by the EPA Administrator. After the Administrator signs the regulation, it is published as a "final rule" in the Federal Register.

2.4 CONSIDERATION OF COSTS

Section 317 of the Act requires an assessment of economic impact with respect to any standard of performance established under Section 111 of the Act. The assessment is required to contain an analysis of: (1) the costs of compliance with the regulation, including the extent to which the cost of compliance varies depending on the effective date of the regulation and the development of less expensive or more efficient methods of compliance; (2) the potential inflationary or recessionary effects of the regulation; (3) the effects the regulation might have on small businesses with respect to competition; (4) the effects of the regulation on consumer costs; and (5) the effects of the regulation on energy use. Section 317 also requires that the economic impact assessment be as extensive as practicable. It should be noted that the costs used in developing these standards were based on 1984 costs; the year the technical analyses were performed. These base year costs, however, would not significantly change the analysis or the requirements of the standards.

The economic impact of a proposed standard upon an industry is usually addressed both in absolute terms and in terms of the control costs that would be incurred as a result of compliance with typical, existing State control regulations. An incremental approach is necessary because both new and existing plants would be required to comply with State regulations in the absence of a Federal standard of performance. This approach requires a detailed analysis of the economic impact from the cost differential that would exist between a proposed standard of performance and the typical State standard.

Air pollutant emissions may cause water pollution problems, and captured potential air pollutants may pose a solid waste disposal problem. The total environmental impact of an emission source must, therefore, be analyzed and the costs determined whenever possible.

A thorough study of the profitability and price-setting mechanisms of the industry is essential to the analysis so that an accurate estimate of potential adverse economic impacts can be made for proposed standards. It is also essential to know the capital requirements for pollution control systems already placed on plants so that the additional capital requirements necessitated by these Federal standards can be placed in proper perspective. Finally, it is necessary to assess the availability of capital to provide the additional control equipment needed to meet the standards of performance.

2.5 CONSIDERATION OF ENVIRONMENTAL IMPACTS

Section 102(2)(C) of the National Environmental Policy Act (NEPA) of 1969 requires Federal agencies to prepare detailed environmental impact

statements on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment. The objective of NEPA is to build into the decision making process of Federal agencies a careful consideration of all environmental aspects of proposed actions.

In a number of legal challenges to standards of performance for various industries, the United States Court of Appeals for the District of Columbia Circuit has held that environmental impact statements need not be prepared by the Agency for proposed actions under Section 111 of the Act. Essentially, the Court of Appeals has determined that the best system of emission reduction requires the Administrator to take into account counter-productive environmental effects of a proposed standard, as well as economic costs to the industry. On this basis, therefore, the Court established a narrow exemption from NEPA for EPA determination under Section 111.

In addition to these judicial determinations, the Energy Supply and Environmental Coordination Act (ESECA) of 1974 (PL-93-319) specifically exempted proposed actions under the Clean Air Act from NEPA requirements. According to Section 7(c)(1), "No action taken under the Clean Air Act shall be deemed a major Federal action significantly affecting the quality of human environment within the meaning of the National Environmental Policy Act of 1979." (15 U.S.C. 793(c)(1)).

Nevertheless, the Agency has concluded that the preparation of environmental impact statements could have beneficial effects on certain regulatory actions. Consequently, although not legally required to do so by Section 102(2)(C) of NEPA, EPA has adopted a policy requiring that environmental impact statements be prepared for various regulatory actions, including standards of performance developed under Section 111 of the Act. This voluntary preparation of environmental impact statements, however, in no way legally subjects the Agency to NEPA requirements.

To implement this policy, a separate section in this document is devoted solely to an analysis of the potential environmental impacts associated with the proposed standards. Both adverse and beneficial impacts in such areas as air and water pollution, increased solid waste disposal, and increased energy consumption are discussed.

2.6 IMPACT ON EXISTING SOURCES

Section 111 of the Act defines a new source as ". . . any stationary source, the construction or modification of which is commenced . . ." after the proposed standards are published. An existing source is redefined as a new source if "modified" or "reconstructed" as defined in amendments to the general provisions of Subpart A of 40 CFR Part 60, which were promulgated in the Federal Register on December 16, 1975 (40 FR 58416).

Promulgation of a standard of performance requires States to establish standards of performance for existing sources in the same industry under Section 111(d) of the Act if the standard for new sources limits emissions

of a designated pollutant (i.e., a pollutant for which air quality criteria have not been issued under Section 108 or which has not been listed as a hazardous pollutant under Section 112). If a State does not act, EPA must establish such standards. General Provisions outlining procedures for control of existing sources under Section 111(d) were promulgated on November 17, 1975, as Subpart B of 40 CFR Part 60 (40 FR 53340).

2.7 REVISION OF STANDARDS OF PERFORMANCE

Congress was aware that the level of air pollution control achievable by any industry may improve with technological advances. Accordingly, Section 111 of the Act provides that the Administrator ". . . shall, at least every 4 years, review and, if appropriate, revise . . ." the standards. Revisions are made to assure that the standards continue to reflect the best systems that become available in the future. Such revisions will not be retroactive, but will apply to stationary sources constructed or modified after the proposal of the revised standards.

3. REACTOR PROCESSES AT SYNTHETIC ORGANIC CHEMICAL MANUFACTURING PLANTS

This chapter presents a description of reactor processes at synthetic organic chemical manufacturing plants. Section 3.1 briefly describes the synthetic organic chemical manufacturing industry (SOCMI) and identifies the segment of the industry that is represented by reactor processes. The chemical reactions used in reactor processes are identified in Section 3.2 and further described in Section 3.5. Section 3.2 also identifies and discusses volatile organic compound (VOC) emission characteristics associated with reactor processes employing many different chemical reactions. Section 3.3 discusses the emission data base that is used to develop projections of emissions from new, modified, and reconstructed reactors in Chapter 6. An estimate of the baseline emissions level is presented in Section 3.4. References are presented in Section 3.6.

3.1 DESCRIPTION OF REACTOR PROCESSES AT SYNTHETIC ORGANIC CHEMICAL MANUFACTURING PLANTS

3.1.1 Introduction

The SOCMI is a large and diverse industry producing over 7,000 intermediate and end-product chemicals from about 15 basic chemicals.¹ These basic chemicals are derived primarily from crude oil, natural gas, and coal. Examples of basic chemicals include benzene, ethylene, propylene, and propane. Basic chemicals are used to produce hundreds of intermediate chemicals, which are subsequently used to manufacture end-product chemicals. Generally, each process level contains more chemicals than the preceding level, and process units manufacturing chemicals at the end of the production system generally have smaller capacities (in terms of production volume) than process units producing the basic materials. Also, the volatilities of the end-product chemicals are typically less than those of basic materials.

A SOCMI process unit may use two broad categories of processes to manufacture organic chemicals: conversion and separation. Conversion processes involve chemical reactions that alter the molecular structure of chemical compounds. Conversion processes comprise the reactor processes segment of a SOCMI plant. Separation processes often follow conversion processes and divide chemical mixtures into distinct fractions. Examples of separation processes are distillation, filtration, crystallization, and extraction.

The SOCMI emissions have been divided into a number of groups according to emission mechanisms to make the development of NSPS more manageable. These major emission groups are fugitives, storage, secondary, and process vents. Sources within each SOCMI group are similar with respect to operating

procedures, emission characteristics, and applicable emission control techniques. Reactor processes are one of several groups constituting process vent emissions. There are two subsets of chemical reactor processes. The focus of this document is upon reactor processes other than air oxidation, which is shown cross hatched in Figure 3-1. Air oxidation processes are the subject of a separate regulatory action because they involve large reactor vent streams and high potential VOC emissions.² In this study, the term "reactor processes" refers to means by which one or more substances, or reactants, (other than air or oxygen-enriched air) are chemically altered such that one or more new organic chemicals are formed.

An estimated six percent of the total VOC emissions from the SOCM I are associated with reactor processes (excluding air oxidation processes).³ For comparison, estimated percentages of the total SOCM I VOC emissions associated with each of the emissions groups are presented in Table 3-1. At present, NSPS have been promulgated for SOCM I fugitives, and standards are currently being developed for distillation operations, air oxidation processes, and volatile organic liquid (VOL) storage tanks.⁴

3.1.2 Scope of Reactor Processes

Over 7,000 chemicals are manufactured by the SOCM I, but only a small percentage of the total number of these chemicals account for the majority of the industry's total production. The development of meaningful and enforceable standards that could be applied to the manufacture of all 7,000 synthetic organic chemicals would require inordinate amounts of time, data, and resources. As a result, the scope of the standards development program for various emission groups of the SOCM I was limited to those chemicals that dominate industry output. These large-volume chemicals are defined as those with annual national production exceeding 45,400 Mg/yr (100 million lb/yr). Production of these large-volume chemicals accounts for approximately 90 percent of national VOC SOCM I emissions because, when emissions do occur from reactor processes, they are generally proportional to production rates.³

Based on 1981 production data, a total of 173 chemicals produced in volumes over 100 million lb/yr are included in the scope of reactor processes.⁵ The list of 173 chemicals, given in Appendix E, does not include polymers or chemicals produced exclusively by biological synthesis. Also excluded from the list is ethanol produced for human consumption. Chemicals that are manufactured exclusively by air oxidation processes or distillation operations are included on the list but are not analyzed here since they are being considered in separate standards development programs.

3.2 CHEMICAL REACTIONS AND REACTOR VOC EMISSIONS

3.2.1 Classification of Chemicals by Reaction Type

Between 30 and 35 different types of chemical reactions are used to produce the 173 high-volume chemicals.⁶ These chemical reactions are discussed in Section 3.5. Some of these chemical reactions are involved in the manufacture of only one or two of the 173 chemicals while others (such

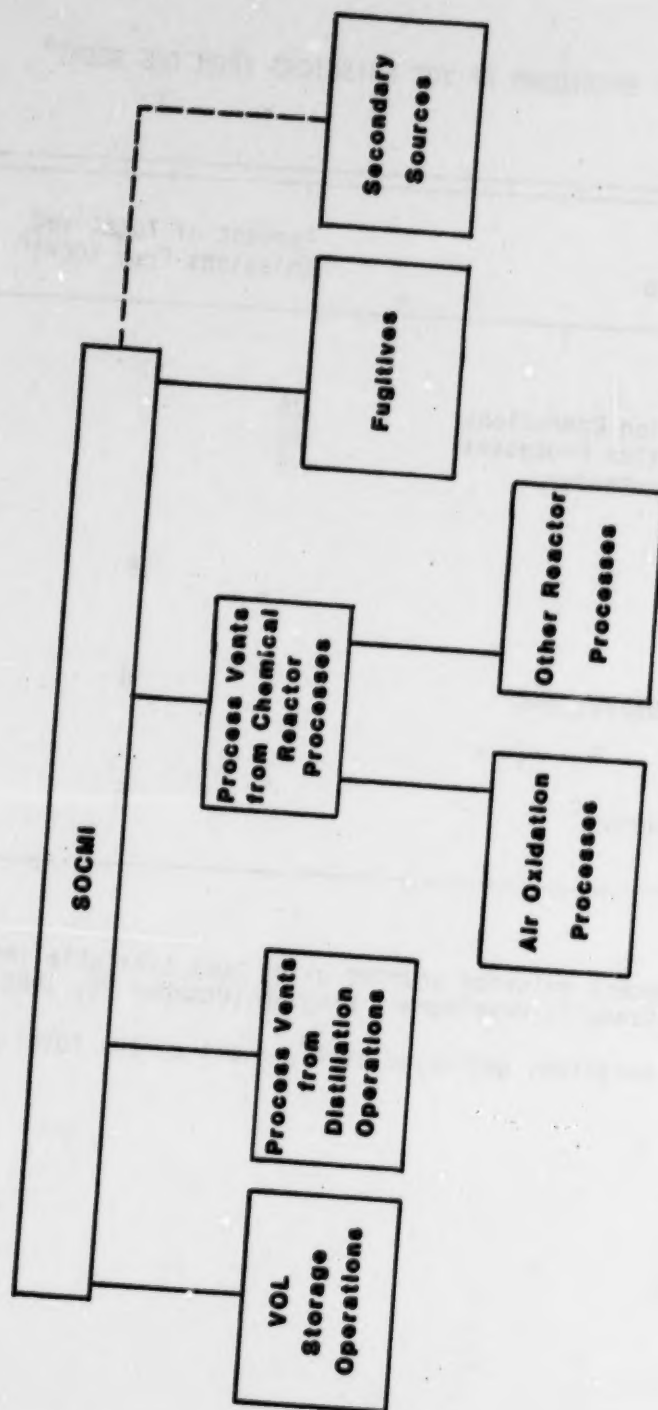


Figure 3-1. Emissions Groups within the SOCMI.

TABLE 3-1. BREAKDOWN OF VOC EMISSIONS FROM THE SOCMI^a

Emissions Group	Percent of Total VOC Emissions From SOCMI ^b
Process Vents	52
Distillation Operations	26
Air Oxidation Processes	20
Reactor Processes	6
Fugitives	35
VOL Storage Operations	8
Secondary Sources ^c	5

^a(Reference 3)

^bEstimates from process emission sources using best available information from SOCMI NSPS standards development program (October 25, 1982).

^cSecondary source emissions estimated as 5 percent of the total of the other sources.

as halogenation, alkylation, and hydrogenation) are used to make more than a dozen chemicals. Table 3-2 identifies most of the chemical reaction types and the number of chemicals produced by each type. The reactions are ranked according to volume of production. In addition, some of the chemicals produced by reactions listed in Table 3-2 do not produce process vent streams. In this document, a process vent stream means any gas stream ducted to the atmosphere directly from a reactor, or indirectly, through the process product recovery system. For example, approximately half of the 23,850 Gg of production from pyrolysis is accounted for by the manufacture of ethylene -- a process that, according to available data, does not produce a process vent stream.

3.2.2 Reactor VOC Emissions

Reactor VOC emissions include all VOC in process vent streams from reactors and product recovery systems. Process product recovery equipment includes devices such as condensers, absorbers, and adsorbers, used to recover product or by-product for use, reuse, or sale. Not included in product recovery equipment are product purification devices involving distillation operations. (Distillation operations are considered under a separate standards development program.)

Reactor processes may be either liquid phase reactions or gas phase reactions. Four potential atmospheric emissions points are shown in Figure 3-2 and include:

- (A) Direct reactor process vents from liquid phase reactors;
- (B) Vents from recovery devices applied to vent streams from liquid phase reactors (Raw materials, products, or by-products may be recovered from vent streams for economic or environmental reasons.);
- (C) Process vents from gas phase reactors after either the primary or secondary product recovery device (Gas phase reactors always have primary product recovery devices.); and
- (D) Exhaust gases from combustion devices applied to any of the above streams.

Some chemical production processes may have no reactor process vent to the atmosphere, while others may have one or more vent streams. Specific examples of vent types A, B, and C are presented in Figures 3-3, 3-4, and 3-5. Each figure represents one of the 173 chemicals covered within the scope of this document.

The production of nitrobenzene by a nitration process is shown in Figure 3-3 and is an example of a liquid phase reaction with an uncontrolled vent stream (Vent Type A). Benzene is nitrated at 55°C (130°F) under atmospheric pressure by a mixture of concentrated nitric and sulfuric acids in a series of continuous stirred-tank reactions. The crude reaction mixture flows to a separator, where the organic phase is decanted from the aqueous waste acid. Emission streams from the reactors and separator are combined and emitted to the atmosphere without any control devices (Vent 1). All available data in the Emission Data Profile (EDP) indicate that controls are not typically applied to this process, and that reactor vents are the

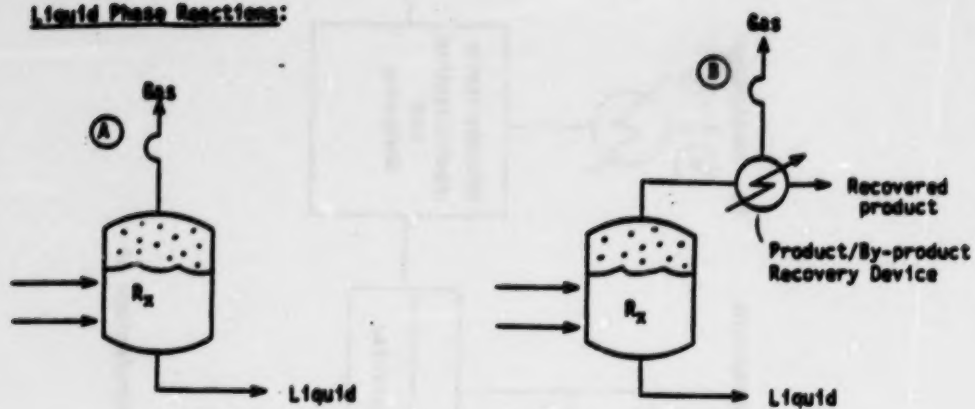
TABLE 3-2. RANKING OF CHEMICAL REACTION TYPES

RANK	Chemical Reaction Type	Number of Chemicals Produced	1981 Annual Production Gg (10 ⁶ lb)
1	Pyrolysis	7	23,850 ^a (52,587)
2	Alkylation	13	6,396 (14,100)
3	Hydrogenation	13	5,580 ^a (12,300)
4	Dehydration	5	5,569 ^a (12,277)
5	Carbonylation/ Hydroformylation	6	5,224 ^a (11,516)
6	Halogenation	23	4,991 ^a (11,003)
7	Hydrolysis/Hydration	8	4,697 (10,356)
8	Dehydrogenation	4	4,401 ^a (9,702)
9	Esterification	12	4,075 ^a (8,983)
10	Dehydrohalogenation	1	3,175 ^a (7,000)
11	Ammonolysis	7	2,759 (6,083)
12	Reforming	4	2,605 (5,744)
13	Oxyhalogenation	1	2,426 (5,349)
14	Condensation	12	2,201 ^a (4,852)
15	Cleavage	2	1,947 (4,293)
16	Oxidation	4	1,750 (3,859)
17	Hydrodealkylation	2	1,492 (3,289)
18	Isomerization	3	942 (2,076)
19	Oxyacetylation	1	878 (1,936)
20	Oligomerization	7	786 ^a (1,696)
21	Nitration	3	728 ^a (1,606)
22	Hydrohalogenation	2	533 (1,174)
23	Reduction	1	333 (734)
24	Sulfonation	4	310 (683)
25	Hydrocyanation	2	208 (458)
26	Neutralization	2	129 (284)
27	Hydrodimerization	1	28 (61)
28	Miscellaneous	6	480 (1,058)
29	Non-reactor processes ^b	26	-

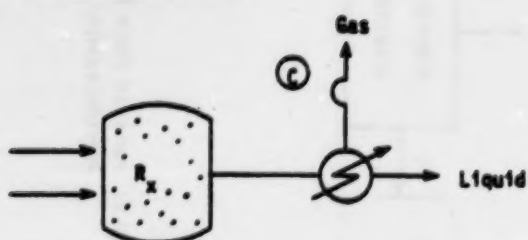
^aProduction data not complete for all chemicals.

^bChemicals produced solely by air oxidation, distillation, or other non-reactor processes.

Liquid Phase Reactions:



Gas Phase Reactions:



Process Vents Controlled by Combustion.

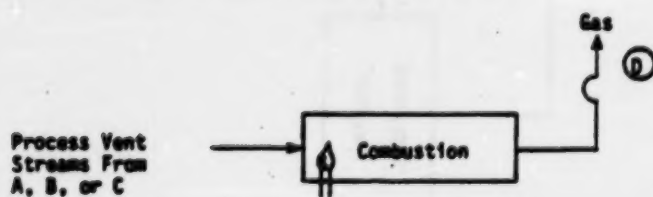


Figure 3-2. General Examples of Reactor-Related Vent Streams.

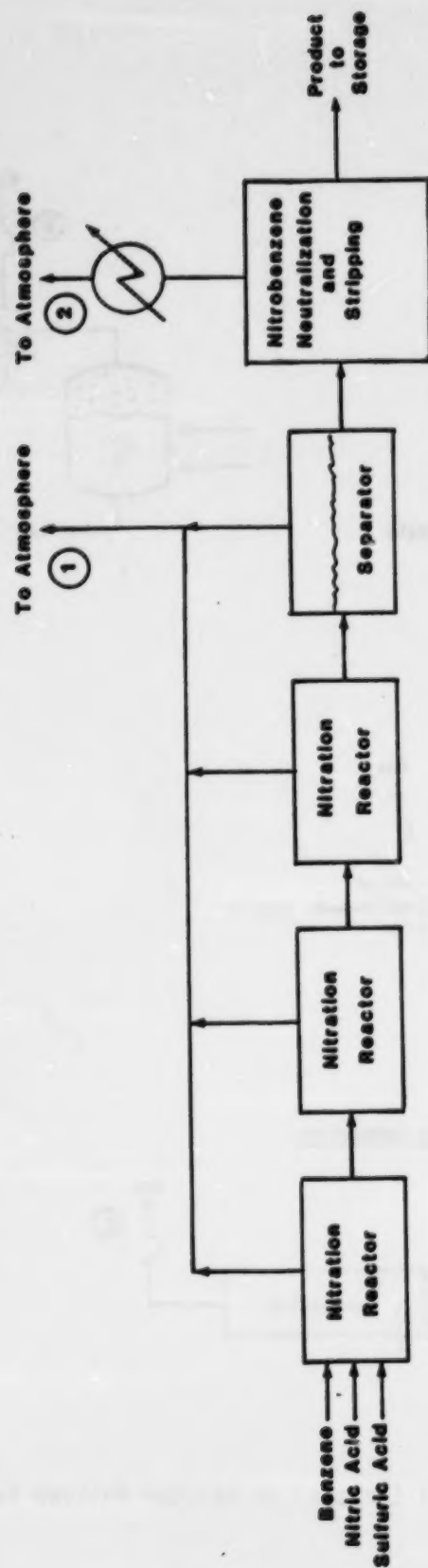


Figure 3-3. Process Flow Diagram for the Manufacture of Nitrobenzene. (Reference 7.)

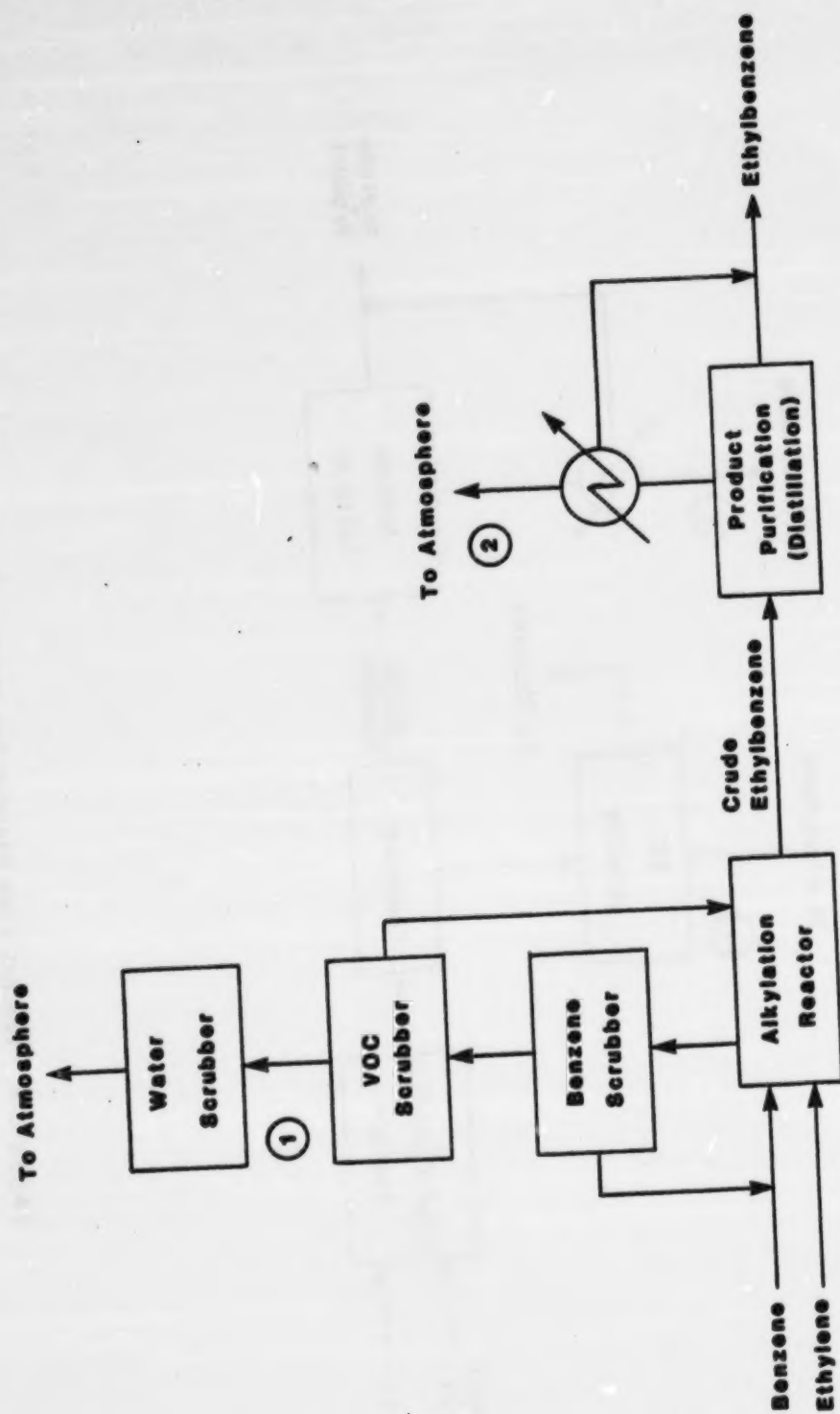


Figure 3-4. Process Flow Diagram for the Manufacture of Ethylbenzene.

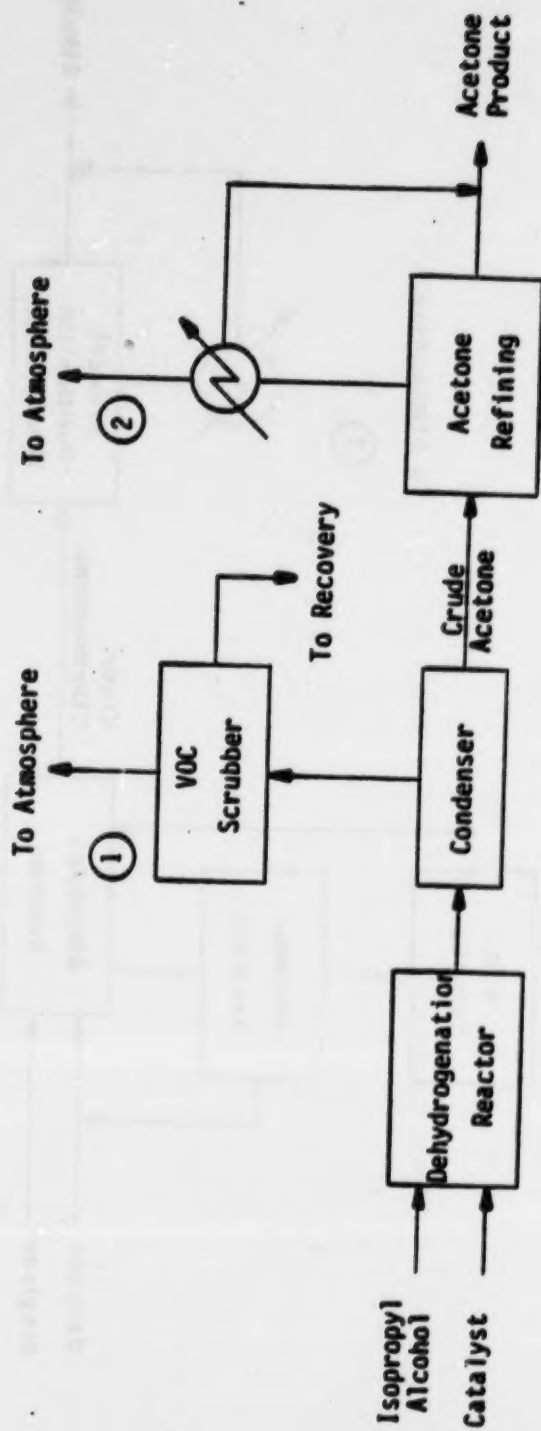


Figure 3-5. Process Flow Diagram for the Manufacture of Acetone.

largest source of VOC in nitrobenzene plants. Recent comments from industry indicate that a new process without vents may now be in use. (See discussion in Section 3.5.)

The production of ethylbenzene is an example of a liquid phase reaction where the vent stream is passed through a VOC recovery device before it is discharged to the atmosphere (Type B). Figure 3-4 depicts an alkylation unit process used to produce ethylbenzene. Ethylene and benzene are combined in the alkylation reactor to form crude ethylbenzene. The process vent stream from the reactor goes through three types of scrubbers before discharging to the atmosphere. The first scrubber recovers the excess benzene reactant from the vent stream and recycles it to the reactor. The second scrubber removes any ethylbenzene product in the vent stream and recycles it to the reactor. Finally, traces of acidic catalyst in the vent stream are removed by a water scrubber before the vent stream is discharged to the atmosphere. Vent 1 in the figure designates the only reactor vent stream for this example. The crude ethylbenzene product stream from the reactor is purified by distillation. The vent stream from the product purification operations (Vent 2) is associated with distillation operations and, therefore, is not considered to be a reactor-related vent stream.

Figure 3-5 shows a dehydrogenation process used to produce acetone. Although this is not the most widely used process to make acetone, it provides a good example of a vapor phase reaction and its associated vent streams (Type C). In this process, isopropyl alcohol is catalytically dehydrogenated to acetone in a vapor-phase reaction at 400 to 500°C (750 to 930°F). The crude acetone then passes through a condenser or primary VOC recovery device. The overheads or process vent stream from the primary condenser then goes through a scrubber and is released to the atmosphere (Vent 1). Acetone is further refined and emissions from the refining process (Vent 2) are again not considered to be reactor-related. Information in the EDP show that other processes used to manufacture acetone have no reactor process vent streams to the atmosphere.

The characteristics of reactor vent streams (i.e., heat content, flowrate, VOC control) vary widely among the numerous chemicals and chemical reactions in the SOCFI. In addition, the numerous possible combinations of product recovery devices and reactors introduce another source of variability among various process units (as defined in Chapter 5) using the same reaction type. The following section describes the emission characteristics of reactor processes.

3.3 EMISSION DATA PROFILE

In order to develop the baseline emissions level, discussed in the next section, an extensive data base for 127 process units at existing SOCFI plants was developed. For the purposes of this discussion, a process unit is any combination of one or more reactors and an associated product recovery system that manufactures the same organic compound as product or by-product at the same site. A plant is constituted by one or more process

units. There are no factors identified in the collection of the data that would introduce systematic bias into the database. It is believed that the EDP is representative of SOCFI reactor processes. The EDP is presented in Appendix C.

Table 3-3 presents an overview of the EDP. As indicated, the EDP represents approximately 50 percent of the 173 chemicals and about 90 percent of the 35 chemical reactions included in the scope of the reactor processes segment of the SOCFI. A total of 17 States are represented in the data profile. Of the process units represented in the profile, about 69 percent are located in Texas and Louisiana.⁸

Emissions data included in the EDP have been grouped by chemical reaction type. Table 3-4 summarizes the VOC emission characteristics of reactor processes using 30 of the 35 chemical reactions considered here. These data represent the process vent stream characteristics following the final gas treatment device (condenser, absorber, or adsorber) but prior to any combustion device.

There is a wide variability in the VOC emission characteristics associated with the various chemical reactions. For example, VOC emission factors range from 0 kg/Gg of product for pyrolysis reactions to 120,000 kg/Gg of product for hydroformylation reactions. Wide variability also exists in the emission characteristics associated with process units using the same chemical reaction. For example, process units using chlorination reactions have VOC emission factors that range from 292 to 9,900 kg/Gg. The variability in process vent stream flowrates and heating values is not as pronounced as the VOC emission factors. Flowrates range from 0 to 537 scm/min and heating values range from 0 to 58.8 MJ/scm.⁸

Although process vent stream characteristics are variable, there are some general observations evident in Table 3-4. First, process units using 11 of the 30 reaction types included in Table 3-4 were reported to have no reactor process vents. These reactions include: amination, ammonolysis, cleavage, etherification, fluorination, hydration, neutralization, oligomerization, phosgenation, pyrolysis, and sulfurization.

A second general observation evident in Table 3-4 is that process units using 6 of the reaction types included in Table 3-4 were reported to have the largest VOC emission factors in the EDP. The reactions include: hydroformylation, chlorination, dehydrogenation, condensation, oxychlorination, and hydrochlorination. The vent streams from process units using these reactions also tend to have both high heating values and a high percentage application of combustion devices.

TABLE 3-3. OVERVIEW OF THE EMISSION DATA PROFILE^a

1. Number of chemicals included in the profile	83
Percent of 173 chemicals represented	48
2. Number of chemical reactions represented in the profile	31
Total number of chemical reactions associated with the 173 chemicals	35
Percent of chemical reactions represented	89
3. Percent of plants in the profile that are from Texas and Louisiana	69
4. Other states represented in the profile:	
Alabama	
California	
Delaware	
Florida	
Georgia	
Kentucky	
Maryland	
Mississippi	
Nevada	
New Jersey	
New York	
Pennsylvania	
Tennessee	
Virginia	
West Virginia	

^aReference 8

TABLE 3-4. SUMMARY OF REACTOR-RELATED VOC EMISSION FACTORS, VENT STREAM HEAT CONTENTS, AND FLOWRATE PRIOR TO COMBUSTION

Chemical Reaction Type	Range (or single value) of Reactor VOC Emission Factors ^a , Kg/Gg	Range (or single value) of Vent Stream VOC Content ^{b,c} g/scm	Percent of Process Units with Vent Streams Using Combustion Control	Range (or single value) of Flowrates ^b scm/min	Range (or single value) of Vent Stream Heat Content ^d MJ/scm
Alkylation	5.95-78.1	3.07-252	33.3	0.24-0.48	0.15-6.74
Amination	0 ^d	0 ^d	0 ^d	0 ^d	0 ^d
Ammonolysis	0 ^d	0 ^d	0 ^d	0 ^d	0 ^d
Carbonylation	443	1.06	100	537	11.0
Catalytic Reforming	DNA ^f	1.72	100	36.5	7.63
Chlorination	292-9,900	0.209-118	44.4	1.13-342	0-45.7
Cleavage	0 ^d	0 ^d	0 ^d	0 ^d	0 ^d
Condensation	8,900	554	100	4.16	39.8
Dehydration	DNA ^f	DNA ^f	0	DNA ^f	DNA ^f
Dehydrogenation	11,400-12,600	36.5-75.0	85.7	16.3-147	10.4-11.2
Dehydrochlorination	4,790	1,097	100	0.283	22.3
Esterification	4.38-594	5.34-21.8	14.3	0.06-2.12	3.8
Etherification	0 ^d	0 ^d	0 ^d	0 ^d	0 ^d
Fluorination	0 ^d	0 ^d	0 ^d	0 ^d	0 ^d
Hydration	0 ^d	0 ^d	0 ^d	0 ^d	0 ^d
Hydrogenation	0-943	0-1,638	83.3	0.09-36.9	12.0-58.8
Hydrochlorination	2,000-14,700	28.1-2,247	80.0	0.566	18.6-47.9
Hydroformylation	120,000	878	100.0	20.6	45.9
Hydrodimerization	1,310	6.69	0	30.6	2.61
Hydrolysis	2.5	0.27	33.3	2.80	0
Neutralization	0 ^d	0 ^d	0 ^d	0 ^d	0 ^d
Nitration	9.95-1,350	0.03-390	33.3	0.37-23.3	0-16.2
Oligomerization	0 ^d	0 ^d	0 ^d	0 ^d	0 ^d
Oxidation (Pure O ₂)	0-3,900	0-2.85	25.0	24.0-345	0-0.15
Oxyacetylation	2.20	3.82	0	0.198	15.2
Oxychlorination (Pure O ₂)	7,180	658	100	8.61	26.6
Phosgenation	0 ^d	0 ^d	0 ^d	0 ^d	0 ^d
Pyrolysis	0 ^d	0 ^d	0 ^d	0 ^d	0 ^d
Sulfonation	29.2	0.014	0.0	52.7	0
Sulfurization (Vapor Phase)	0 ^d	0 ^d	0 ^d	0 ^d	0 ^d

^aEmission factors are expressed in terms of Kg of VOC emitted per Gg of chemical produced and represent emissions to the atmosphere from the final gas treatment device (if used), but before combustion (if used).

^bRanges are due to (1) different chemicals produced by the chemical process and (2) different controls used at the process units.

^cAll values represent emission stream characteristics after the final product recovery device and before combustion (if used).

^dNo reactor vent streams are associated with chemicals manufactured by this chemical process.

^eLittle or no flow reported for this vent stream.

^fDNA - data not available.

A general observation concerning all the units in the EDP is that some reactor vent streams contain potentially toxic air pollutants. An examination of some of the units in the EDP shows that chlorobenzene, ethylene dichloride, and vinylidene chloride are emitted from reactor processes in varying amounts. All of these pollutants are currently under assessment by EPA for potential regulation under Section 112 of the Clean Air Act. The units at which these emissions occur are presented in Appendix C and include plant numbers CHL-1, CHL-2, CHL-4, CHL-6, CHL-7, CHL-9, CHL-10, DEHC-1, and OXYC-1.

Appendix C details the information collected for the process units included in the EDP. For each process unit, information is provided on the chemical produced, the chemical unit process used, and any product/by-product recovery and VOC control equipment. Vent stream characteristics and VOC emissions are also given for each process unit where data are available. The key vent stream characteristics for each process unit are the process vent stream flowrate, heat content, and VOC content downstream of the final recovery devices, but upstream of combustion devices. In most cases, these vent stream characteristics were calculated based on information supplied for each process unit.

Table 3-5 summarizes the distribution of recovery and combustion devices for the 127 units in the EDP. Fifty-two percent (or 66 units) of the total 127 process units included in the EDP have reactor process vent streams. Of these 66 units, combustion devices are used for 56 percent of the vent streams and are estimated to control about 94 percent of VOC emissions from all process units in the EDP for which emission data are available.⁹ Plants using combustion devices tend to have vent streams with relatively large flowrates and moderate to high heat contents. Twenty percent of the vent streams in the profile have no VOC combustion control device, while 24 percent use only noncombustion devices as the method of VOC control. From examining the data in the profile, combustion is not usually used on vent streams with heat contents less than 6 MJ/scm (163 Btu/scf).

Two types of vent streams do not have VOC combustion controls applied. Process vent streams with small flowrates are often not controlled despite moderate to high heat contents and VOC concentrations. Similarly, vent streams with high flowrates but low heat contents, <3.0 MJ/scm (<80 Btu/scf), are typically not controlled.

3.4 BASELINE EMISSIONS

The baseline emissions level is defined as the estimate of national VOC emissions that will occur in the absence of an NSPS from new, modified, and reconstructed reactor process units coming on-line over a 5-year period, from July 1, 1985, to July 1, 1990. Assuming no reactor process NSPS were to be proposed in 1985, the baseline emissions level is calculated for the year 1990. Baseline emissions from reactor processes are estimated to be

TABLE 3-5. DISTRIBUTION OF RECOVERY AND COMBUSTION
DEVICES FOR THE 127 PROCESS UNITS IN THE
EMISSION DATA PROFILE

Process Unit Description	Number of Process Units (Percentage)
Units with reactor vent streams	66 (52 percent) ^a
Units with unknown vent stream status	1
Units using combustion devices	37 (56 percent) ^b
Distribution of combustion devices	
Incinerators	13 units
Flares	11 units
Boilers	7 units
Process heaters	5
Unspecified combustion device	1
Units with no VOC treatment ^c	13
Units using only noncombustion devices for VOC control ^d	16

^aPercent of 127 process units in the Emission Data Profile.

^bPercent of the 66 process units with reactor vent streams.

^cIncludes units with acid gas removal or no devices at all.

^dNoncombustion devices include condensers and VOC scrubbers.

3,300 Mg per year. The purpose of establishing a baseline emissions level is to provide a benchmark from which to compare the environmental and energy impacts and cost impacts of the regulatory alternatives presented in Chapters 7 and 8, respectively.

The baseline emissions level estimate was derived from the EDP together with projections for the number of new, modified, and reconstructed process units projected to come on-line between 1985 and 1990. Projections of demand and estimates of replacements for each of the 173 chemicals was used to determine the number, size, and type of new, modified, and reconstructed reactor process units that would likely come on-line during 1985-1990. It was assumed that each of these process units would have emission characteristics similar to those in the EDP. Thus, the baseline emission level estimate takes into account both (1) the variability in anticipated production rates for various products and (2) the variation in emissions by reaction type. A description of the method of determining the baseline VOC emissions level follows. Chapter 9 reviews the projections for new, modified, and reconstructed process units.

3.4.1 Method of Calculating Baseline Emissions

Baseline emissions are constituted by the emissions from all new, modified, and reconstructed process units, including those emissions from units with vent streams projected to be combusted in the absence of an NSPS and those emissions from units projected to be uncombusted in the absence of an NSPS. It is estimated that of the 133 new, modified, and reconstructed process units that are projected to come on-line between 1985 and 1990, 56 process units will not use combustion devices in the absence of an NSPS. Total uncontrolled emissions from these units are estimated to be 2,400 Mg/yr. As discussed in Chapters 6 and 7 these emissions were calculated using the process unit capacity and emission characteristics presented in Table 6-1.

Emissions are also estimated to come from all new, modified, and reconstructed process units which are projected to use combustion devices in the absence of an NSPS. Although combustion is projected to be used at these units, complete VOC destruction will not occur and some VOC will be emitted from the outlets of the combustion devices. Based on the projections for new and replacement capacity and other data presented in Table 9-18, it is estimated that 22 of the 173 chemicals considered here will have new and replacement process units built which will use combustion devices in the absence of an NSPS. It was assumed a process unit making a specific chemical would apply combustion in the absence of an NSPS if: (1) the majority of process units in the EDP making that chemical use combustion or (2) the majority of process units using the same process units as that specific chemical use combustion (this method used if: (1) could not be used). Table 9-18 summarizes the combustion status of each chemical considered. Emissions from these units are estimated by multiplying the estimated new and replacement capacity of each chemical with the appropriate VOC emission factor for each chemical then summing the emissions for all 22 chemicals.¹⁰ The capacity was multiplied by a 77 percent capacity factor to estimate the total amount of chemicals produced in the fifth year of the NSPS.²⁵ The

development of the VOC emission factors used here is discussed in Chapter 6. The total emissions are then multiplied by 0.02 to account for the emissions removed by the combustion devices. (Assuming that the combustion devices applied will achieve 98-weight-percent VOC destruction). It is estimated that 910 Mg/yr of VOC will be emitted from new, modified, and reconstructed process units where combustion devices are applied in the absence of an NSPS.¹⁰ Therefore, total baseline emissions are estimated to be 3,300 Mg/yr (910 Mg/yr from 77 process units with combustion devices and 2,400 Mg/yr from the 56 process units without combustion devices).

3.4.2 State Regulations and Industrial Practices Impacting Baseline Emissions

It is estimated from the EDP that over 90 percent of VOC emissions from reactor processes are currently combusted. Baseline emissions are influenced by the existing Federal and State regulations affecting VOC emissions from SOCMIs plants. The degree of VOC control required by applicable State regulations varies in stringency from State to State. About 90 percent of the process units in the EDP that currently combust their vent streams would be required to combust under Louisiana law, and 82 percent would combust under Texas law. The following discussion illustrates the variability of State standards among Texas, Louisiana, and New Jersey. Approximately 50 percent of the existing SOCMIs process units (of which reactor process units are a single subgroup) are located in these three States.¹¹

Texas regulations require facilities emitting more than 45 kg/day (100 lb/day) or 110 kg/yr (250 lb/yr), depending on the true vapor pressure of the VOC, to incinerate the waste gas stream at 704°C (1,300°F). This is considered equivalent to approximately 95 percent VOC reduction.¹² Louisiana requires incineration of VOC waste gas streams at a minimum temperature of 704°C (1,300°F) for at least 0.3 second in a direct flame afterburner or equally effective device. However, control requirements may be waived if the offgas stream is less than 100 tons per year or if the offgas will not support combustion without auxiliary fuel.¹³ New Jersey uses a sliding scale, based on the degree of difficulty in controlling the VOC emission source, to establish allowable emission rates for individual sources. Depending on the vapor pressure, concentration, and amount of the waste stream VOC, the New Jersey regulation requires from 0 to 99.7 percent VOC reduction.¹⁴

In addition to existing regulations, a variety of industrial practices or site-specific vent stream control practices may be instituted that impact the baseline control level for reactor processes. In some cases, these industrial practices may result in VOC emissions reductions that go beyond that required under existing regulations. These practices may be instituted for safety or economic reasons. For instance, intermittent reactor vent streams may be flared for safety reasons to prevent the accumulation of explosive gases. For some chemical processes it may be economical to operate high efficiency product/by-product recovery devices on reactor vent streams or to utilize the heat content of reactor offgas through combustion in boilers or process heaters. For example, as indicated in Appendix C,

process heaters are typically used at methanol process units. An example of other industrial practices that may have a slight impact on baseline emissions is the scrubbing of process vent streams to remove acidic or caustic compounds. Changing feedstocks in the chemical production process (e.g., use of cleaner or dirtier feedstocks) and process modifications (e.g., catalyst changes, reactor temperature, pressure changes, etc.) may also affect emissions.

3.5 CHEMICAL REACTION DESCRIPTIONS

This section presents a brief description of the major chemical reactions represented in the SOCM. Only descriptions of the larger volume chemicals are included in this discussion. Each chemical reaction description contains a discussion of the process chemistry that characterizes each chemical reaction and the major products resulting from the chemical reaction. In addition, process vent stream characteristics are presented for chemicals where data are available.⁶ Descriptions of the major large-volume chemical reactions are presented in alphabetical order in the remainder of this section.⁶

Alkylation

Alkylation is the introduction of an alkyl radical into an organic compound by substitution or addition. There are six general types of alkylation, depending on the substitution or addition that occurs:

1. substitution for hydrogen bound to carbon;
2. substitution for hydrogen attached to nitrogen;
3. addition of metal to form a carbon-to-metal bond;
4. substitution for hydrogen in a hydroxyl group of an alcohol or phenol;
5. addition of alkyl halide, alkyl sulfate, or alkyl sulfonate to a tertiary amine to form a quaternary ammonium compound; and
6. miscellaneous processes such as addition of an alkyl group to sulfur or silicon.

The major chemical products of alkylation reactions are ethylbenzene and cumene. The single largest category of alkylation products are refinery alkylates used in gasoline production. Other chemical products of alkylation processes include linear alkylbenzene, tetramethyl lead, and tetraethyl lead.

In general, based on data for production of ethylbenzene, cumene, and linear alkylbenzene, reactor VOC emissions from alkylation processes appear to be small compared to other unit processes. The commercial synthesis of ethylbenzene from ethylene and benzene is an example of the first type of alkylation reaction described above. The reaction can be carried out in two ways. One production process involves a low pressure liquid-phase reaction method using an aluminum chloride catalyst, while the other process operates in the vapor phase at high pressure with various solid catalysts. Data from one plant that produces ethylbenzene by liquid-phase alkylation indicate that reactor VOC emissions are relatively small. (Although no emissions data are available for the vapor-phase alkylation process, the associated

VOC emissions are expected to be small due to the high operating pressure.) Reactor offgas from the liquid-phase alkylator is vented to a VOC scrubber where unreacted benzene is removed from the gas stream and recycled to the reactor. According to data contained in the EDP, the scrubber vent stream contains inerts and a small amount of VOC and is vented to the atmosphere at a rate of approximately 0.5 scm/m (17 scfm). The estimated heat content of the vent stream is 6.7 MJ/scm (181 Btu/scf). The VOC emissions to the atmosphere from the gas scrubber are estimated to be 2.7 kg/hr (16 lb/hr).

Cumene is produced by the vapor-phase catalytic alkylation of benzene with propylene. The reaction takes place at 690 kPa (100 psia) in the presence of a phosphoric acid catalyst. No reactor streams are vented, and thus no reactor VOC emissions to the atmosphere are associated with this process at the five cumene plants included in the EDP. Excess benzene required for the alkylation reaction is recovered by distillation in the cumene product purification process and recycled to the reactor.

Dodecylbenzenes, also referred to as linear alkylbenzenes (LAB), are produced by alkylation of mono-olefins or chlorinated n-paraffins with benzene. VOC emissions from both processes are small or nonexistent. In the case of the mono-olefin production route, only high purity raw materials can be used, thus eliminating the introduction of dissolved volatiles. Furthermore, the HF catalyst used in the process is a hazardous chemical and a potential source of acidic emissions that must be minimized. As a result, operators of one mono-olefin production route for LAB indicate that process vent streams have little or no flow associated with them.¹⁵ The alkylation reaction producing LAB from chlorinated n-paraffins generates HCl gas and some VOC by-products. The potential to emit reactor VOC from this process is greater than for the mono-olefin process due to formation of degradation and other VOC by-products. Benzene and HCl are removed from the process vent stream before discharging to the atmosphere. Data from a plant producing LAB from chlorinated n-paraffins indicate that the process vent stream following the scrubber is intermittent and emits no VOC to the atmosphere.

Ammonolysis

Ammonolysis is the process of forming amines by using ammonia or primary and secondary amines as aminating agents. Another type of ammonolytic reaction is hydroammonolysis, in which amines are formed directly from carbonyl compounds using an ammonia-hydrogen mixture and a hydrogenation catalyst. Ammonolytic reactions may be divided into four groups:

1. Double decomposition - NH_3 is split into $-\text{NH}_2$ and $-\text{H}$; the $-\text{NH}_2$ becomes part of the amine while the $-\text{H}$ reacts with a radical like $-\text{Cl}$ that is being substituted;
2. Dehydration - NH_3 serves as a hydrant, and water and amines result;
3. Simple addition - both fragments of the NH_3 molecule ($-\text{NH}$ and $-\text{H}$) become part of the newly formed amine; and
4. Multiple activity - NH_3 reacts with the produced amines resulting in formation of secondary and tertiary amines.

The major chemical products of ammonolysis reactions are acrylonitrile and carbamic acid. Reactor emissions from acrylonitrile production are covered in the air oxidation processes NSPS, so they are not discussed here. Two other categories of ammonolysis products are ethanolamines and methylamines.

Based on information on ethanolamine production, ammonolytic processes appear to be a negligible source of reactor VOC emissions. Ethanolamines, including mono-, di-, and triethanolamines, are produced by a simple addition reaction between ethylene oxide and aqueous ammonia. According to information on two process units producing ethanolamines, no reactor VOC are emitted to the atmosphere from this process. The reactor product stream is scrubbed to recover the excess ammonia required for the reaction before proceeding to the product finishing unit.

The manufacture of methylamines involves a vapor-phase dehydration reaction between methanol and ammonia. In addition to methylamines, di- and trimethylamines are also formed by the reaction. Although no process unit data for this process are included in the EDP, available information suggests that reactor VOC emissions from the process are small or negligible. Staged distillation immediately follows the reactor to separate the coproducts. As a result, all potential VOC emissions to the atmosphere are associated with distillation operations and are not reactor-related. (Any VOC emissions from distillation vents would be considered under the standards development program for distillation operations.)

Carbonylation/Hydroformylation

Carbonylation/hydroformylation reactions are used to make aldehydes and/or alcohols containing one additional carbon atom. Carbonylation is the combination of an organic compound with carbon monoxide. Hydroformylation, often referred to as the oxo process, is a variation of carbonylation in which olefins are reacted with a mixture of carbon monoxide and hydrogen in the presence of a catalyst. Major chemical products of carbonylation/hydroformylation reactions are acetic acid, n-butyraldehyde, and methanol.

Carbonylation/hydrogenation processes typically generate relatively large process vent streams with high heat contents, compared to other unit processes. Thus, process vent streams from these reactions are normally combusted.

One carbonylation process for acetic acid manufacture reacts liquid methanol with gaseous carbon monoxide at 20 to 70 MPa (2,900 to 10,200 psia) in the presence of a catalyst. At one plant that produces acetic acid by this high pressure process, the reactor products are passed through two gas liquid separators. The vent from the first separator, consisting primarily of carbon dioxide and carbon monoxide, is scrubbed and sent to carbon monoxide recovery. The vent from the second separator is scrubbed to recover excess reactant and then combined with other waste gas streams and flared. No data are available on the VOC content of the two vent streams.

However, the only point where reactor VOC are potentially emitted to the atmosphere is the vent from the second separator, which is ultimately discharged to a flare.

In the oxo process for producing n-butyraldehyde, propylene is reacted with synthesis gas (CO and H₂) in the liquid phase at 20 to 30 MPa (2,900 to 4,400 psia). An aromatic liquid such as toluene is used as the reaction solvent. A relatively large amount of VOC is contained in the process vent stream for this reaction. Industry comment from the Chemical Manufacturers Association (CMA) suggests that this process has generally been replaced by an unnamed, low VOC-emitting process. No data, however, are available for this process. Information from one plant producing n-butyraldehyde by the oxo process indicates that the reactor vent stream consists of hydrogen, carbon monoxide, and VOC and is used as fuel in an industrial boiler. Prior to combustion, the estimated vent stream flow rate at this plant is 21 scm/m (730 scfm) and the heating value is 46 MJ/scm (1,233 Btu/scf). The VOC flowrate prior to combustion is approximately 1,100 kg/hr (2,394 lb/hr).

Cleavage

Acid cleavage is the process by which an organic chemical is split into two or more compounds with the aid of an acid catalyst. This chemical reaction is associated with production of two major chemicals, phenol and acetone.

Production of phenol and acetone begins with oxidation of cumene to cumene hydroperoxide. The cumene hydroperoxide is usually vacuum distilled to remove impurities and then agitated in 5 to 25 percent sulfuric acid until it cleaves to phenol and acetone. The mixture is neutralized to remove excess sulfuric acid, phase separated, and distilled. One process unit producing phenol and acetone from cumene hydroperoxide reports little or no flow in the process vent stream at the cleavage reactor. High purity of the cumene hydroperoxide intermediate is the major reason for this "no flow" vent.

Condensation

Condensation is a chemical reaction in which two or more molecules combine, usually with the formation of water or some other low-molecular weight compound. Each of the reactants contributes a part of the separated compound. Chemical products made by condensation include acetic anhydride, bisphenol A, and ethoxylate nonylphenol.

The EDP includes data on four condensation processes. Reactor emissions to the atmosphere from condensation processes are expected to be small. Emissions from acetic anhydride production are minimized by combustion of the process vent stream. There are no reactor VOC emissions from bisphenol, or ethoxylated nonylphenol production. (Bisphenol A has emissions from distillation operations only.)

Acetic anhydride is produced by the condensation of acetic acid and ketene. Ketene for the reaction is made by pyrolysis of acetic acid. After water removal, the gaseous ketene is contacted with glacial acetic acid liquid in absorption columns operated under reduced pressure. The process vent stream from the absorber contains acetic acid, acetic anhydride, traces of ketene, and any reaction by-product gases generated. The VOC content of the vent stream is particularly dependent on impurities that may be contained in the acetic acid feed, such as formic or propionic acid, that cause side reactions to occur. Scrubbers are normally used to remove acetic acid and acetic anhydride from the vent stream. At two process units producing acetic anhydride the vent streams are burned as supplemental fuel in pyrolysis furnaces. No data on the vent stream characteristics or VOC content were provided for one of these process units; however, data from the other source on acetic anhydride production identify the major components of the process vent stream after scrubbing to be carbon monoxide, carbon dioxide, and VOC. The typical VOC flowrate of the vent stream after scrubbing was estimated to be 138 kg/hr (305 lb/hr), based on assumptions about the purity of the reactants.

Bisphenol A is produced by reacting phenol with acetone in the presence of HCl as the catalyst. Numerous by-products are formed in the reaction that must be eliminated in order to generate high-purity bisphenol A. Removal of these by-products requires distillation and extraction procedures, and thus no reactor vents to the atmosphere are associated with this process.

Dehydration

Dehydration reactions* are a type of decomposition reaction in which a new compound and water are formed from a single molecule. Reactions in which two molecules condense with the elimination of water and the formation of a new compound are included in the process of condensation. The major chemical product of dehydration is urea.

Commercial production of urea is based on the reaction of ammonia and carbon dioxide to form ammonium carbamate, which in turn is dehydrated to urea and water. The unreacted ammonium carbamate in the product stream is decomposed to ammonia and carbon dioxide gas. A portion of the ammonia is removed from the process vent stream leaving primarily carbon dioxide to be vented to the atmosphere. No data are included in the EDP for VOC emissions from urea production, but one study indicates that VOC emissions from urea synthesis are negligible. Urea is the only chemical of those that use dehydration to be included in the EDP.

*This process refers to chemical dehydration and does not include physical dehydration in which a compound is dried by heat. Stucco produced by heating gypsum to remove water is an example of physical dehydration.

Dehydrogenation

Dehydrogenation is the process by which a new chemical is formed by the removal of hydrogen from the reactant. Aldehydes and ketones are prepared by the dehydrogenation of alcohols. Chemicals produced by dehydrogenation processes include acetone, bivinyl, cyclohexanone, methyl ethyl ketone (MEK), and styrene.

In general, dehydrogenation processes produce relatively large, hydrogen-rich process vent streams that are either used as a fuel in process heaters or industrial boilers or as a hydrogen feed for other processes. The two process units for which data are available have high heat content process vent streams. These occur as a result of the hydrogen generated in the dehydrogenation reaction. Although these process vent streams can be quite large, there is generally little VOC contained in them.

Acetone and MEK are produced by similar processes involving the catalytic dehydrogenation of alcohols. There are four process units in the EDP that produce MEK via the dehydrogenation of sec-butanol. In all cases a hydrogen-rich process vent stream is produced. One process unit uses a VOC scrubber to remove MEK and sec-butanol from the process vent stream prior to flaring. In all four process units, reactor VOC emissions are well controlled or nonexistent. One acetone production process unit has an additional reactor process vent stream on a degasser directly following the reactor. This degasser reduces the pressure on the product stream to allow storage of the product at atmospheric pressure. The pressure reduction step causes dissolved hydrogen and low boiling point VOC to escape from the liquid-phase product. This purge stream, which is relatively small, is routed to a water scrubber to remove some VOC before it is released to the atmosphere. This is the only acetone production process unit in the EDP that stores the acetone as an intermediate product, and as a result, it is the only plant with a degasser process vent stream.

Two process units in the EDP manufacture styrene via the hydrogenation of ethylbenzene. One plant produces a hydrogen-rich (90 percent by volume) process vent stream that is normally combusted to recover the heat content. The other plant produces a process vent stream that is first condensed and then combusted in a flare system. The vent stream flowrate is relatively large (16 scm/m (574 scfm)); the stream contains 23 percent VOC including toluene, benzene, ethylbenzene, and styrene. The heat content is estimated to be 11 MJ/scm (300 Btu/scf), which would support combustion without the addition of supplemental fuel.

Dehydrohalogenation

In the dehydrohalogenation process, a hydrogen atom and a halogen atom, usually chlorine, are removed from one or more reactants to obtain a new chemical. This chemical reaction is used to produce vinyl chloride, vinylidene chloride, and cyclohexene.

Vinylidene chloride is made by dehydrochlorinating 1,1,2-trichloroethane with lime or aqueous sodium hydroxide. The reactor product is separated and purified by distillation. The process vent stream at one vinylidene chloride process unit is incinerated and then scrubbed with caustic before discharging to the atmosphere. Before incinerating, the vent stream flowrate is estimated to be 0.28 scm/m (10 scfm) and the heat content is 22 MJ/scm (600 Btu/scf). The VOC emission rate of the vent stream is approximately 19 kg/hr (41 lb/hr). At a second plant producing vinylidene chloride, no reactor vent streams are used. The process vent streams are associated with distillation operations.

Esterification

Esterification is the process by which an ester is derived from an organic acid and an alcohol by the exchange of the ionizable hydrogen atom of the acid and an organic radical. The major chemical product of esterification is dimethyl terephthalate. Other esterification products include ethyl acrylate and ethyl acetate.

VOC emissions associated with esterification processes are small based on information on the production of methyl methacrylate, ethyl acrylate, and ethyl acetate.

Ethyl acrylate is produced by the catalytic reaction of acrylic acid and ethanol. The vent stream flowrate from reactor equipment producing ethyl acrylate in one process unit is reported to be 2.1 scm/m (75 scfm). The heat content for this stream is estimated to be 3.8 MJ/scm (102 Btu/scf). The VOC emission rate of the vent stream is 2.8 kg/hr (6.1 lb/hr).

Methyl methacrylate is produced by esterifying acetone and hydrogen cyanide with methanol. Limited information is available on reactor VOC emissions from this process. The EDP includes one plant producing methyl methacrylate; the process vent stream at this plant is combusted in an incinerator. Although the incinerator is used primarily to destroy VOC in offgases from another plant process, combustion of the methyl methacrylate process vent stream in the incinerator allows the plant to use less supplemental fuel by recovering the heat content of the vent stream. No vent stream flowrate or heat content data are available for this plant; however, the VOC emission rate is estimated to be very low (0.05 kg/hr (0.1 lb/hr)).

Ethyl acetate production involves an esterification reaction between acetic acid and ethanol. Two process units producing ethyl acetate are included in the EDP. Following condensation of the process vent stream to recover product, both process units discharge the vent stream to the atmosphere. Vent stream data reported by one of the process units indicate the VOC content of the vent stream to be low, i.e., 0.2 kg/hr (0.5 lb/hr).

Halogenation

Halogenation is the process whereby a halogen (chlorine, fluorine, bromine, iodine) is used to introduce one or more halogen atoms into an organic compound. (Reactions in which the halogenating agent is a halogen acid, such as hydrochloric acid, are included in a separate unit process called hydrohalogenation.) The chlorination process is the most widely used halogenation process in industry; fluorination is used exclusively in the manufacture of fluorocarbons. The major products of halogenation reactions are ethylene dichloride, phosgene, and chlorinated methanes and ethanes.

Reactor VOC emissions from halogenation reactions vary from no emissions to 51 kg/hr (113 lb/hr). Most chlorination reactors vent to scrubbers or condensers where HCl generated in the chlorination reaction is removed. Some VOC reduction occurs along with HCl removal by these devices. Also, some vent streams are combusted prior to discharge to the atmosphere. Purity of the feed materials (including chlorine) is a major factor affecting the amount of reactor VOC emissions vented to the atmosphere.

Ethylene dichloride can be produced by direct chlorination of ethylene or by oxychlorination of ethylene. Most ethylene dichloride is currently made by a "balanced" process that combines direct chlorination of ethylene and oxychlorination of ethylene. The direct chlorination process reacts acetylene-free ethylene and chlorine in the liquid phase. The oxyhalogenation process using oxygen for the manufacture of ethylene dichloride is included in the reaction description for oxyhalogenation. Reactor VOC emissions from ethylene dichloride production by direct chlorination vary according to process vent stream treatment. HCl is generated by the chlorination reaction and is typically removed from the process vent stream by a caustic scrubber. The vent stream following the scrubber may be discharged to the atmosphere, recycled to the reactor, or incinerated. The EDP contains information on three ethylene dichloride plants which use the direct chlorination process as part of the "balanced" process. The process vent stream characteristics for the three plants indicate a range of gas flowrates of 1.1 to 7.6 scm/m (40 to 267 scfm) and a range of heat contents of 1.5 to 46 MJ/scm (40 to 1,228 Btu/scf). The process vent stream with the highest heat content (i.e., 46 MJ/scm) is incinerated before venting to the atmosphere.

The fluorination reactions producing dichlorodifluoromethane and trichlorotrifluoroethane involve the replacement of a chlorine in carbon tetrachloride with fluorine. At two plants surveyed, no reactor VOC emissions are associated with these fluorination processes. The two plants report no process vent stream discharges to the atmosphere. Instead, process vent streams occur from distillation operations.

Hydrodealkylation

Hydrodealkylation is the process by which methyl groups, or larger alkyl groups, are removed from hydrocarbon molecules and replaced by hydrogen atoms. Hydrodealkylation is primarily used in petroleum refining

to upgrade products of low value, such as heavy reformate fractions, naphthalenic crudes or recycle stocks from catalytic cracking. In particular, hydrodealkylation is used in the production of high-purity benzene and naphthalene from alkyl aromatics such as toluene.

The EDP contains no information on emissions from hydrodealkylation processes. In the case of benzene production, the process vent stream containing unconverted toluene is recycled to the reactor, and no reactor VOC emissions are vented.¹⁶

Hydrohalogenation

Hydrohalogenation is the process in which a halogen atom is added to an organic compound using a halogen acid, such as hydrogen chloride. The major chemical products of this reaction are methyl chloride and ethyl chloride.

Approximately 80 percent of methyl chloride is produced by the vapor-phase reaction of methanol and hydrogen chloride.¹⁷ In three process units the process vent stream is condensed to remove excess HCl; some VOC is also removed by the condensers. Of the nine plants that manufacture methyl and ethyl chloride included in the EDP, five have no reactor process vent streams, one discharges the noncondensibles directly to the atmosphere, and three route the noncondensable stream to combustion devices. The VOC content of a methyl chloride vent stream is 76 kg/hr (168 lb/hr).

Hydrolysis/Hydration

Hydrolysis is the process in which water reacts with another substance to form two or more new substances. Hydration is the process in which water reacts with a compound without decomposition of the compound. These processes are a major route in the manufacture of alcohols and glycols, such as ethanol, ethylene glycols, and propylene glycols. Another major product of hydrolysis is propylene oxide.

Propylene oxide is produced by hydrolysis of propylene chlorohydrin with an alkali (usually NaOH or $\text{Ca}(\text{OH})_2$). The product vent stream is condensed to remove the propylene oxide product and the noncondensibles are discharged to the atmosphere. Data from a process unit that produces propylene oxide indicate the flowrate of the vent stream following the condenser to be about 2.8 scm/m (99 scfm) and the estimated VOC emissions to the atmosphere to be 0.05 kg/hr (0.1 lb/hr).

Sec-butyl alcohol is produced by absorbing n-butenes in sulfuric acid to form butyl hydrogen sulfate that is then hydrolyzed to sec-butyl alcohol and dilute sulfuric acid. The reactor product is steam stripped from the dilute acid solution and purified by distillation. Information on the sec-butyl alcohol production at one process unit does not indicate any specific process vents. All process vents at this process unit are reported to be flared so that any reactor VOC emissions would be combusted.

In general, production of chemicals by hydrolysis/hydration processes generate little or no reactor VOC emissions. Based on production information for ethylene glycol and propylene glycol, these hydration reactors do not have process vent streams associated with them. Ethylene glycol and propylene glycol are produced by hydrating ethylene oxide and propylene oxide, respectively. The reactions for both chemicals result in production of di- and tri- glycols as coproducts. Following the reactor, the glycols are separated and purified by distillation. No reactor VOC emissions are vented to the atmosphere from the glycol process units in the EDP.

Hydrogenation

Hydrogenation is the process in which hydrogen is added to an organic compound. The hydrogenation process can involve direct addition of hydrogen to the double bond of an unsaturated molecule, replacement of oxygen in nitro-containing organic compounds to form amines, and addition to aldehydes and ketones to produce alcohols. The major chemical products of hydrogenation reactions include cyclohexane, aniline, n-butyl alcohol, hexamethylene diamine, 1,4-butanediol, cyclohexanone, and toluene diamine.

In general, reactor VOC emissions from hydrogenation reactions appear to be small in comparison with other chemical reactions. However, combustion devices are typically associated with the vent streams of hydrogenation processes. Excess hydrogen in these vent streams makes them suitable for combustion in most cases.

Hexamethylene diamine is made by hydrogenation of adiponitrile. Reactor VOC emissions from hexamethylene diamine production are small according to information on three process units in the EDP. Excess hydrogen used in the reaction is recovered from the vent stream and recycled to the reactor. At two of these process units, the process vent streams are used as fuel in a plant boiler. The average vent stream flowrate following hydrogen recovery at the three process units is 14.0 scm/m (496 scfm) and the average heat content is 21 MJ/scm (562 Btu/scf). The VOC content of the noncombusted vent stream at the process unit that does not use combustion is approximately 3 kg/hr (6.6 lb/hr). The VOC content of the combusted streams at the other two process unit is estimated to be negligible prior to combustion.

Cyclohexane is produced by the liquid-phase hydrogenation of benzene. In this process, both cyclohexane and hydrogen are recovered from the process vent stream. Information from one cyclohexane plant indicates that there is usually no flow in the vent stream following product and hydrogen recovery. The process vent stream after these recovery systems is discharged to the atmosphere only during emergencies, and the stream is vented to the flare system for VOC destruction during such upset conditions.

Cyclohexanone, 1,4-butanediol, and toluene diamine production involve the hydrogenation of phenol, 2-butyne-1,4-diol, and 2,4-dinitrotoluene, respectively. The process vent stream for these hydrogenation reactions are ultimately combusted in incinerators, boilers, or flares. Precombustion vent stream characteristic data are available for only one of these vent streams - n-Butyl alcohol. For this process unit, the vent stream flowrate is estimated to be .09 scm/m (3.2 scfm) and the heating value 59 MJ/scm (1,578 Btu/scf). The VOC flowrate prior to combustion is approximately 9 kg/hr (19.6 lb/hr).

Isomerization

During isomerization, organic compounds are converted by heat and a catalytic reaction that changes the arrangement of atoms in a molecule, but not the number of atoms. Catalysts include aluminum chloride, antimony chloride, platinum, and other metals. Temperatures range from 400 to 480°C (750 to 900°F), and pressures range from 7 to 50 atm.¹⁸

Isomerization is used in petroleum refining to convert straight-chain hydrocarbons into branched-chain hydrocarbons. An example is the conversion of n-butane to isobutane.¹⁸ Emissions from this process would be expected to be small, as with other high-temperature and high-pressure reactor processes in the EDP.

Neutralization

Neutralization is a process used to manufacture linear alkylbenzene; benzenesulfonic acid, sodium salt; dodecylbenzene sulfonic acid, sodium salt; and oil-soluble petroleum sulfonate, calcium salt. Diagrams of all of the production processes show no reactor process vent streams.⁸

Nitration

Nitration is the unit process in which nitric acid is used to introduce one or more nitro groups (NO_2) into organic compounds. Aromatic nitrations are usually performed with a mixture of nitric acid and concentrated sulfuric acid. Nitrobenzene and dinitrotoluene are the major products of nitration reactions.

Reactor VOC emissions to the atmosphere from nitration reactions appear to be relatively low based on information on production of nitrobenzene and dinitrotoluene. Nitrobenzene production involves the direct nitration of benzene using a mixture of nitric acid and sulfuric acid. Only a small quantity of by-products, primarily nitrated phenols, are produced by the reaction. The reaction is normally blanketed with nitrogen gas to reduce fire and explosion hazards. At one process unit producing nitrobenzene, waste acid is removed from the reactor product stream by a separator followed by recovery of excess benzene by distillation. Vent streams from the reactor and separator are combined and discharged directly to the atmosphere. Industry comment from CMA has stated that a new but unnamed process without reactor process vents is now in operation. No data, however, are available for this process. The main components of the

combined vent streams are nitrogen and benzene. The EDP nitrobenzene nitration process has a combined vent stream flowrate estimated to be 0.37 scm/m (13 scfm) and an approximate heat content of 16 MJ/scm (434 Btu/scf). VOC emissions to the atmosphere from the vent streams are 8.6 kg/hr (19 lb/hr).

Dinitrotoluene is produced by nitration of toluene in two stages using different acid mixtures. As in the case of nitrobenzene production, the waste acid is separated and recycled. Two process units producing dinitrotoluene operate scrubbers on the reactor vent streams to remove VOC. Following scrubbing, one plant discharges the vent stream to the atmosphere while the other incinerates the vent stream. No data is available on the characteristics of the incinerated vent stream. The flowrate of the nonincinerated vent stream following the scrubber is estimated to be 23 scm/m (822 scfm). Heat content of the vent stream is negligible. Estimated VOC emissions to the atmosphere are 0.05 kg/hr (0.1 lb/hr).

Oligomerization

In the oligomerization process, molecules of a single reactant are linked together to form larger molecules consisting of from 2 to about 10 of the original molecules. Oligomerization is used to make several chemicals including alcohols, dodecene, heptene, nonene, and octene. Typically, it is a high temperature, high pressure process.^{19,20} Diagrams for all of the chemical production processes show no reactor process vent streams.²¹⁻²³ Other chemical unit processes with similar high pressure characteristics, such as pyrolysis, emit little or no VOC.

Oxidation

Oxidation of organic chemicals is the addition of one or more oxygen atoms into the compound. The oxidation processes considered here include pure oxygen oxidation and chemical oxidation. (Air oxidation processes are a separate subcategory of reactor processes for standards development purposes and includes oxygen-enriched air processes as discussed in Section 3.1.) An example of pure oxygen oxidation is the production of ethylene oxide using pure oxygen and ethylene. The production of adipic acid from nitric acid is an example of chemical oxidation.

Ethylene oxide can be produced by oxidation using air or pure oxygen. In the pure oxygen process, ethylene, oxygen and recycle gas are reacted under pressures of 1 to 3 MPa (150 to 440 psia). Two reactor process vent streams are reported by one process unit that produces ethylene oxide by pure oxygen oxidation. At this plant, the reactor effluent is sent through an ethylene oxide absorber. The offgas from this absorber is routed to the carbon dioxide removal system. A portion of the vent stream from the carbon dioxide absorber system is recycled to the reactor while the remainder is used as fuel in industrial boilers. The carbon dioxide absorber liquid is regenerated, and the removed carbon dioxide is vented to the atmosphere. The portion of the vent stream from the CO₂ absorber that is sent to a boiler has an approximate flowrate of 176 scm/m (6,200 scfm) and a heat

content of 13 MJ/scm (340 Btu/scf). The estimated discharge rate to the atmosphere from the CO₂ absorber liquid regenerator vent is 345 scm/m (12,187 scfm), and the heat content is 0.15 MJ/scf (4 Btu/scf). Prior to combustion in the boiler, the VOC flowrate of the first vent stream is 0.59 kg/hr (1.3 lb/hr). For the uncontrolled vent stream, VOC emissions to the atmosphere are estimated to be 59 kg/hr (130 lb/hr).

In adipic acid production, an alcohol ketone mixture is oxidized using nitric acid. Adipic acid from the reactor is stripped of nitrogen oxides produced by the reaction and then refined. Of the three process units producing adipic acid included in the EDP, two of the process unit discharge the stripper offgas to the atmosphere. Estimated vent stream flowrates at the three process units range from 24 to 132 scm/m (848 to 4,653 scfm). The heating values of all three vent streams are negligible and there are no VOC emissions from any of these process units.

Oxyacetylation

Oxyacetylation is the process in which oxygen and an acetyl group are added to an olefin to produce an unsaturated acetate ester. Oxyacetylation is used in a new commercial process to make vinyl acetate.

Vinyl acetate is produced from ethylene, acetic acid, and oxygen. Reactor VOC emissions from one vinyl acetate production process unit are small. The estimated vent stream flowrate and heating value are 0.2 scm/m (7 scfm) and 15 MJ/scm (407 Btu/scf), respectively. The VOC flowrate prior to combustion is approximately 0.05 kg/hr (0.1 lb/hr).

Oxyhalogenation

In the oxyhalogenation process, a halogen acid is catalytically oxidized to the halogenated compound with air or oxygen. The main oxyhalogenation process is oxychlorination, in which hydrogen chloride is catalytically oxidized to chlorine with air or oxygen. (Oxychlorination processes using air are included in the analyses for air oxidation processes.) The oxychlorination process is used in the production of ethylene dichloride.

As described previously, most ethylene dichloride is produced by the "balanced process" that combines oxychlorination and direct chlorination of ethylene. In the oxychlorination reaction, ethylene, hydrogen chloride, and oxygen or air are combined. Emissions from air oxychlorination reactions used in ethylene dichloride production are included in the air oxidation processes NSPS. Only emissions from oxygen oxychlorination reactions are considered here. At one process unit producing ethylene dichloride by oxychlorination using oxygen, the reactor effluent is condensed, and excess ethylene is recycled to the reactor. A small portion of the recycle stream is vented to prevent a buildup of impurities. The vent stream is incinerated in order to comply with State implementation plans (SIPs) and to reduce vinyl chloride emissions that are regulated under a NESHAP. The vent stream flowrate prior to incineration is approximately 8.5 scm/m (304 scfm) and the estimated heat content is 27 MJ/scm (713 Btu/scf). The VOC flowrate in the vent stream is estimated to be 340 kg/hr (748 lb/hr). Following incineration, the estimated VOC emissions to the atmosphere are 6.8 kg/hr (15 lb/hr).

Phosgenation

Phosgenation is the process in which phosgene (COCl_2) reacts with an amine to form an isocyanate, or with an alcohol to form a carbonate. Toluene diisocyanate is the major chemical product of this chemical unit process.

Toluene diisocyanate is produced by phosgenating toluene diamine. At one process unit, the reactor vent is routed through distillation columns for product/by-product recovery and purification. Thus, no reactor VOC emissions are vented to the atmosphere from the process.⁷

Pyrolysis

Pyrolysis is a chemical reaction in which the chemical change of a substance occurs by heat alone. Pyrolysis includes thermal rearrangements into isomers, thermal polymerizations, and thermal decompositions. The major use of this process is in the production of ethylene by the steam pyrolysis of hydrocarbons. Other pyrolysis products include ketene (a captive intermediate for acetic anhydride manufacture) and by-products of ethylene production such as propylene, divinyl, ethylbenzene, and styrene.

Ethylene and other olefins can be produced from a variety of hydrocarbon feeds, including natural gas liquors, naphtha, and gas-oil. Maximum ethylene production is achieved by adjusting furnace temperature and steam-to-hydrocarbon ratios. Pyrolysis gases from the furnace are cooled, compressed, and separated into the desired products. As in refinery operations, the economics of olefins production make recovery of gaseous products desirable. Thus, process vent streams to the atmosphere are minimized. The ethylene process unit included in the EDP reports no process vent streams to the atmosphere.

The first step in the manufacture of acetic anhydride is production of ketene. Ketene and water are produced by pyrolysis of acetic acid. At two plants producing acetic anhydride, the pyrolysis products are cooled and separated prior to acetic anhydride formation. No process vent streams are associated with the pyrolysis reaction to produce ketene.

Sulfonation

Sulfonation is the process by which the sulfonic acid group (SO_2OH), or the corresponding salt, or sulfonyl halide is attached to a carbon atom. "Sulfonation" can also be used to mean treatment of any organic compound with sulfuric acid, regardless of the nature of products formed.²⁴

Isopropyl alcohol is made by sulfonation of propylene to isopropyl hydrogen sulfate and subsequent hydrolysis to isopropyl alcohol and sulfuric acid.¹⁸

Many detergents are made by the sulfonation of mixed linear alkylbenzenes. These include benzenesulfonic acid and dodecylbenzene sulfonic acid. To manufacture these, the linear alkylbenzenes are

sulfonated with SO_3 or oleums of various strengths. One process uses diluted SO_3 vapor in a continuous operation. The reaction and heat removal occurs in a thin film on a cooled reactor surface. The process forms almost entirely the p-sulfonic acid.¹⁸

The EDP contains emissions data on one sulfonation process unit controlled only with a caustic scrubber. It has extremely low uncombusted VOC emissions (0.05 kg/hr or 0.1 lb/hr) even though the vent stream rate is relatively large (52 scm/m or 1,863 scfm).

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4. EMISSION CONTROL TECHNIQUES

This chapter describes the control techniques and associated emission reduction effectiveness for reactor process vents of the synthetic organic chemical manufacturing industry (SOCMI). The effectiveness of combustion systems is examined with respect to their principles of operation, advantages, and disadvantages.

The SOCMI process vent streams show a great variety in volume flows, chemical compositions, and volatile organic compound (VOC) concentrations. This chapter concentrates on combustion control devices since it is a VOC control method universally applicable to SOCMI reactor process vent streams, although it is not necessarily the best for a given process.

Effectiveness and specificity of condensers, absorbers, adsorbers, and catalytic oxidizers may be affected by changes in waste stream conditions. These conditions include flowrate, VOC concentration, chemical and physical properties of VOC, waste stream contaminants, and waste stream temperature. Analysis of reactor process VOC emissions control by these methods would be unwieldy. Also, control systems based on condensation or absorption are generally used as recovery devices, and the removal efficiencies decrease as the VOC concentrations decrease.

Combustion control, however, is much less dependent on process and vent stream conditions than the other control techniques. Incinerators and flares are the only demonstrated VOC combustion controls which are applicable to all SOCMI reactor processes. Flares, however, can only be used on nonhalogenated vent streams. Both incinerator and flare cost and efficiency determinations require a limited amount of vent stream data (volume flow, VOC emission rate, net heating value, and corrosion properties). The choice of incinerator and flare combustion controls as the control techniques for analysis yields conservative estimates of energy, economic, and environmental impacts since combustion control is relatively expensive and energy-intensive.

All new incinerators, if properly designed, adjusted, maintained, and operated, can achieve at least a 98-weight-percent VOC reduction or 20 ppmv exit concentration, whichever is less stringent. This control level can be achieved by incinerator operation at conditions which include a maximum of 1,600°F and 0.75 second residence time. Flares can also achieve at least a 98-weight-percent VOC reduction or 20 ppmv exit concentration. However, to meet such reduction levels, the flare must meet the specifications discussed later in this chapter.

Process modification, improvements in product recovery, and use of additional control devices are possible routes to lower emission levels. This chapter discusses the advantages and disadvantages of using recovery devices such as absorbers, adsorbers, and condensers alone, or in conjunction with VOC control devices such as flares, boilers and thermal and catalytic oxidizers to achieve reduction of VOC emissions.

Boilers can be useful as VOC control devices only when the vent stream volume flow is not large enough to upset the combustion process. Furthermore, the vent stream must either have sufficient oxygen to be used as combustion air or have a sufficiently high heating value to be used as part of the fuel input.

All SOCOMI reactor processes use a combination of absorption devices, condensers, or carbon adsorption units for product recovery (or for recovery of unreacted raw material). These devices are usually designed to recover only as much of the VOC as is economically feasible and therefore would not be considered control devices. However, in some plants, these devices are designed to remove more than that amount which is economically justified. In this case, the devices operate both for product recovery and as control devices for emission reduction or to reduce the pollutant load on some other final control device.

4.1 NONCOMBUSTION CONTROL DEVICES

The noncombustion control devices discussed in this section include adsorbers, absorbers, and condensers. While many devices may remove some VOC from the process stream (e.g., gas conditioning devices such as some water scrubbers) and may be broadly characterized as a noncombustion control device, this discussion is limited to those devices used specifically and primarily for VOC recovery. Because noncombustion control devices recover products, by-products, and/or unused reactants, they may be essential to process economics, providing a cost benefit. The following three sections present a process description and identify the VOC removal efficiency and applicability of each device to reactor process vent streams.

Noncombustion devices are generally applied to recover reactant, product, or by-product VOC from process vent streams. The chemical structure of the VOC removed is usually - although not always - unaltered. Of the 66 units identified in Appendix C that have reactor process vent streams, 13 apply absorbers to recover VOC, 19 apply condensers, and none apply adsorbers. Thirteen units vent to the atmosphere from the reactor without any VOC recovery or combustion. Although noncombustion devices are widely applied in industry, no one device is universally applicable to all reactor process vent streams because: (1) reactor processes produce a wide variety of vent streams with very different characteristics, and (2) the performance of noncombustion devices will vary depending upon the characteristics of a particular stream. This is generally not the case for combustion devices, where a consistent VOC emission destruction can be achieved regardless of the amount and type of VOC present in the vent

stream. The conditions under which the noncombustion systems may not be applicable to reactor process vent streams are identified in the following sections.

4.1.1 Condensation

4.1.1.1 Condensation Process Description. Condensation is a process of converting all or part of the condensible components of a vapor phase into a liquid phase. This is achieved by the transfer of heat from the vapor phase to a cooling medium. If only a part of the vapor phase is condensed, the newly formed liquid phase and the remaining vapor phase will be in equilibrium. In this case, equilibrium relationships at the operating temperatures must be considered. The heat removed from the vapor phase should be sufficient to lower the vapor phase temperature to at or below its dewpoint temperature (i.e., the temperature at which the first drop of liquid is formed).

Condensation devices are of two types: surface condensers and contact condensers.¹ Surface condensers are shell-and-tube type heat exchangers. The coolant and the vapor phases are separated by the tube wall and they never come in direct contact with each other. Surface condensers require more auxiliary equipment for operation but can recover valuable VOC without contamination by the coolant, minimizing waste disposal problems. Only surface condensers are considered in the discussion of control efficiency and applicability since they are used more frequently in industry.

The major equipment components used in a typical surface condenser system for VOC removal are shown in Figure 4-1. This system includes: (1) shell and tube dehumidification equipment, (2) shell-and-tube heat exchanger, (3) refrigeration unit, and (4) VOC storage tanks and operating pumps. Most surface condensers use a shell-and-tube type heat exchanger to remove heat from the vapor.² As the coolant passes through the tubes, the VOC vapors condense outside the tubes and are recovered. The coolant used depends upon the saturation temperature of the VOC stream. Chilled water can be used down to 7°C (45°F), brines to -34°C (-30°F), and chlorofluorocarbons below -34°C (-30°F).³ Temperatures as low as -62°C (-80°F) may be necessary to condense some VOC streams.⁴

4.1.1.2 Condenser Control Efficiency. VOC removal efficiency of a condenser is dependent upon the type of vapor stream entering the condenser, and on condenser operating parameters (flowrate and temperature of the cooling medium). High VOC removal efficiencies are achievable for condensers, but the design and operation of condensers for large heat removals from dilute VOC streams may be costly. Efficiencies of condensers in actual operation usually vary from 50 to 95 percent.⁵

4.1.1.3 Applicability of Condensers. A primary condenser system is used in 19 out of 66 units with vent streams (about 29 percent) in the EDP. In some cases, additional (secondary) condensers are used to recover more VOC from the vent stream exiting the primary condenser. Condensers are sometimes present as accessories to vacuum generating devices (e.g., barometric condensers). Based on these data, condensers are the most widely used product recovery device for reactor vent streams.⁶

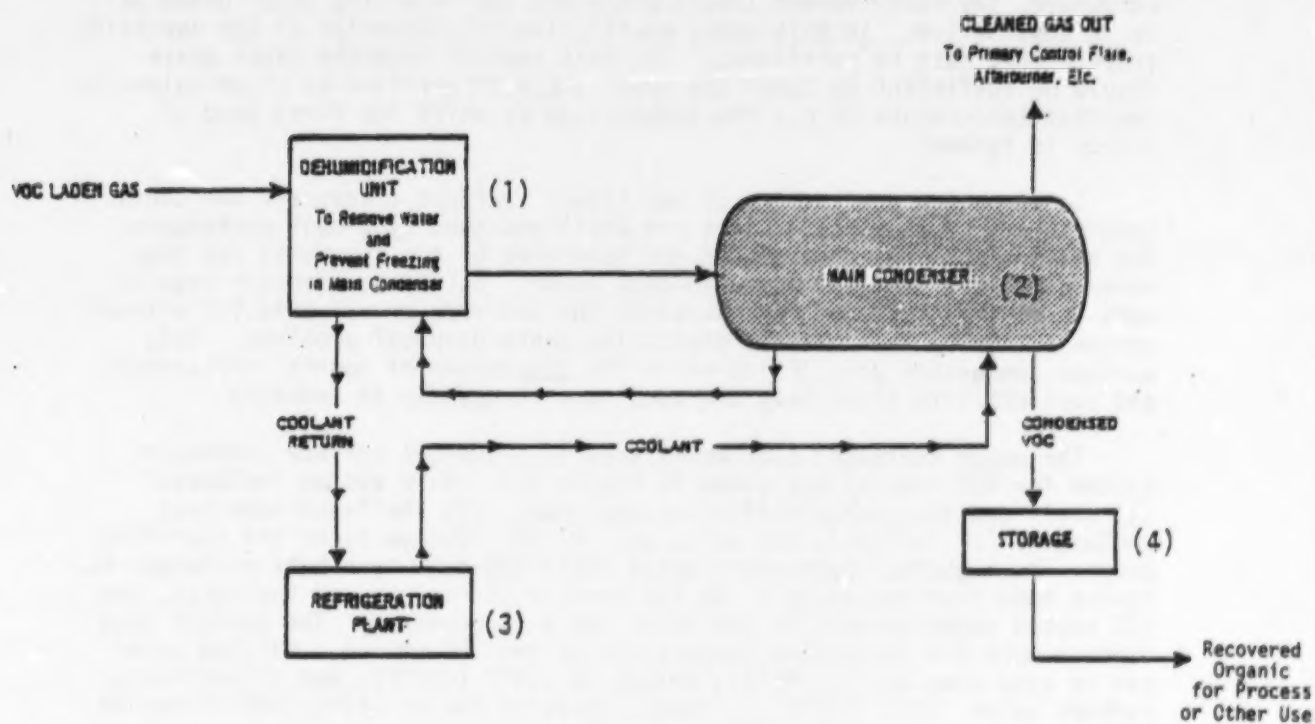


Figure 4-1. Condensation system.

Condenser systems are not well suited for vent streams containing VOC with low boiling points.⁷ In addition, condensers are not well suited for vent streams with low concentrations of VOC, such as streams containing large quantities of inerts such as carbon dioxide, air, or nitrogen. Low boiling point VOC and inerts contribute significantly to the heat load that must be removed from the vent stream, resulting in costly design specifications and/or operating costs. In addition, some low boiling point VOC cannot be condensed at normal operating temperatures.⁸ In the EDP, a number of process units produce reactor vent streams containing low boiling point VOC. For example, process units producing chlorinated methanes have vent streams with substantial amounts of methane, methyl chloride, and methylene chloride. These compounds are not readily condensed and, as a result, are usually vented to the atmosphere or destroyed in a combustion device.

4.1.2 Absorption

4.1.2.1 Absorption Process Description. The mechanism of absorption consists of the selective transfer of one or more components of a gas mixture into a solvent liquid. The transfer consists of solute diffusion and dissolution into a solvent. For any given solvent, solute, and set of operating conditions, there exists an equilibrium ratio of solute concentration in the gas mixture to solute concentration in the solvent. The driving force for mass transfer at a given point in an operating absorption tower is related to the difference between the actual concentration ratio and the equilibrium ratio.⁹ Absorption may only entail the dissolution of the gas component into the solvent or may also involve chemical reaction of the solute with constituents of the solution.¹⁰ The absorbing liquids (solvents) used are chosen for high solute (VOC) solubility and include liquids such as water, mineral oils, nonvolatile hydrocarbon oils, and aqueous solutions of oxidizing agents like sodium carbonate and sodium hydroxide.¹¹

Devices based on absorption principles include spray towers, venturi scrubbers, packed columns, and plate columns. Spray towers require high atomization pressure to obtain droplets ranging in size from 500 to 1,000 μm in order to present a sufficiently large surface contact area.¹² Spray towers generally have the least effective mass transfer capability of the absorption techniques discussed above and, thus, are restricted to particulate removal and control of high-solubility gases such as sulfur dioxide and ammonia.¹³ Venturi scrubbers have a high degree of gas-liquid mixing and high particulate removal efficiency but also require high-energy input and have relatively short contact times. Therefore, their use is also restricted to high-solubility gases.¹⁴ As a result, VOC control by gas absorption is generally accomplished in packed or plate columns. Packed columns are mostly used for handling corrosive materials, for liquids with foaming or plugging tendencies, or where excessive pressure drops would result from use of plate columns. They are less expensive than plate columns for small-scale operations where the column diameter is less than 0.6 m (2 ft). Plate columns are preferred for large-scale operations, where internal cooling is desired or where low liquid flowrates would inadequately wet the packing.¹⁵

A schematic of a packed tower is shown in Figure 4-2. The gas to be absorbed is introduced at the bottom of the tower (1) and allowed to rise through the packing material (2). Solvent flows from the top of the column, countercurrent to the vapors (3), absorbing the solute from the gas phase and carrying the dissolved solute out of the tower (4). Cleaned gas exits at the top for release to the atmosphere or for further treatment as necessary. The saturated liquid is generally sent to a stripping unit where the absorbed VOC is recovered. Following the stripping operation the absorbing solution is either recycled back to the absorber or sent to a treatment facility for disposal.

The major tower design parameters to be determined for absorbing any substance are column diameter and height, system pressure drop, and liquid flowrate required. These parameters are derived from considering the total surface area provided by the tower packing material, the solubility and concentrations of the components, and the quantity of gases to be treated.

4.1.2.2 Absorption Control Efficiency. The VOC removal efficiency of an absorption device is dependent on the solvent selected and on design and operating conditions. For a given solvent and solute, an increase in absorber size or a decrease in the operating temperature can increase the VOC removal efficiency of the system. It may be possible in some cases to increase VOC removal efficiency by a change in the absorbent.

Systems that utilize organic liquids as solvents usually include stripping and recycle of the solvent to the absorber. In this case the VOC removal efficiency of the absorber is also dependent on the solvent stripping efficiency.

4.1.2.3 Applicability of Absorption. Absorption is attractive if a significant amount of VOC can be recovered for reuse. As noted earlier, 13 out of 66 units with vent streams (about 20 percent) in the EDP use absorption devices. These units produce ethylene oxide and monochlorobenzene and use absorbers to recover reactant for reuse as a feedstock material.

Absorption is not usually considered for use when the VOC concentration in a process vent stream is below 200 to 300 ppmv.¹⁶ Furthermore, the use of absorption is subject to the availability of an appropriate solvent for a particular VOC.

A number of chemical processes use absorption systems as an integral part of the production scheme. A typical acetic anhydride manufacturing facility is an example of one such production scheme. Acetic anhydride is produced via the pyrolysis of acetic acid to form ketene. The ketene produced in the pyrolysis furnaces contains by-products and other impurities. Ketene is separated from these by-products and impurities by contacting the product stream with glacial acetic acid in a ketene absorber. Ketene is absorbed from the product stream and routed to further processing and eventual acetic anhydride purification.

4.1.3 Adsorption

4.1.3.1 Adsorption Process Description. Adsorption is a mass-transfer operation involving interaction between gaseous and solid phase components.

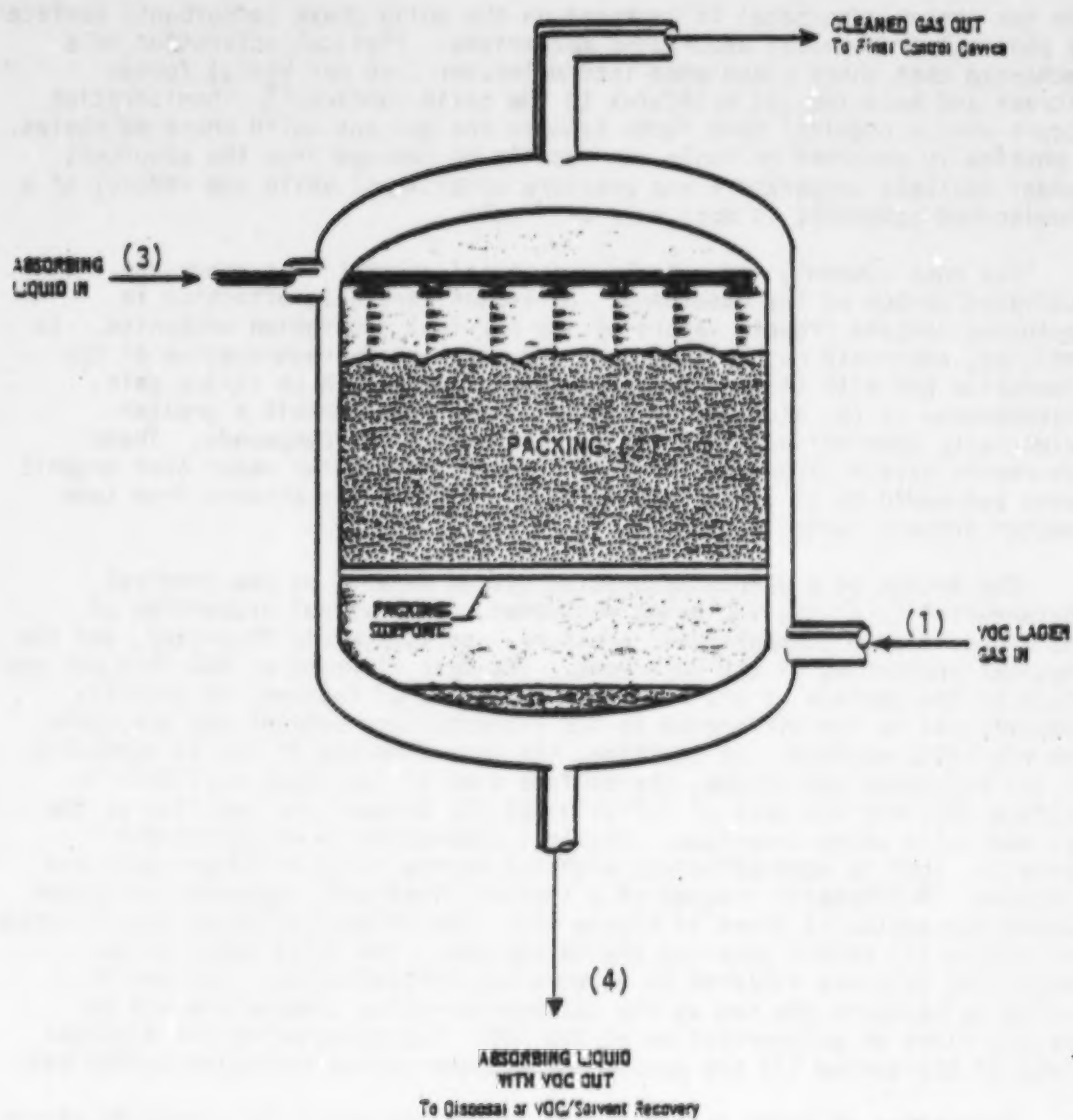


Figure 4-2. Packed tower for gas absorption.

The gas phase (adsorbate) is captured on the solid phase (adsorbent) surface by physical or chemical adsorption mechanisms. Physical adsorption is a mechanism that takes place when intermolecular (van der Waals) forces attract and hold the gas molecules to the solid surface.¹⁷ Chemisorption occurs when a chemical bond forms between the gas and solid phase molecules. A physically adsorbed molecule can readily be removed from the adsorbent (under suitable temperature and pressure conditions) while the removal of a chemisorbed component is much more difficult.

The most commonly encountered industrial adsorption systems use activated carbon as the adsorbent. Activated carbon is effective in capturing certain organic vapors by the physical adsorption mechanism. In addition, adsorbate may be vaporized for recovery by regeneration of the adsorption bed with steam. Oxygenated adsorbents such as silica gels, diatomaceous earth, alumina, or synthetic zeolites exhibit a greater selectivity than activated carbon for capturing some compounds. These adsorbents have a strong preferential affinity for water vapor over organic gases and would be of little use for high moisture gas streams from some reactor process vents.¹⁸

The design of a carbon adsorption system depends on the chemical characteristics of the VOC being recovered, the physical properties of the offgas stream (temperature, pressure, and volumetric flowrate), and the physical properties of the adsorbent. The mass flowrate of VOC from the gas phase to the surface of the adsorbent (the rate of capture) is directly proportional to the difference in VOC concentration between the gas phase and the solid surface. In addition, the mass flowrate of VOC is dependent on the adsorbent bed volume, the surface area of adsorbent available to capture VOC, and the rate of diffusion of VOC through the gas film at the gas and solid phase interface. Physical adsorption is an exothermic operation that is most efficient within a narrow range of temperature and pressure. A schematic diagram of a typical fixed bed, regenerative carbon adsorption system is given in Figure 4-3. The process offgases are filtered and cooled (1) before entering the carbon bed. The inlet gases to an adsorption unit are filtered to prevent bed contamination. The gas is cooled to maintain the bed at the optimum operating temperature and to prevent fires or polymerization of the VOC. Vapors entering the adsorber stage of the system (2) are passed through the porous activated carbon bed.

Adsorption of inlet vapors occurs in the bed until the activated carbon is saturated with VOC. The dynamics of the process may be illustrated by viewing the carbon bed as a series of layers or mass-transfer zones, as illustrated by (3a, b, c) in Figure 4-3. Gases entering the bed are highly adsorbed first in zone (a). Because most of the VOC is adsorbed in zone (a), very little adsorption takes place in zones (b) and (c). Adsorption in zone (b) increases as zone (a) becomes saturated with organics, and eventually adsorption occurs in zone (c). When the bed is completely saturated (breakthrough) the incoming VOC-laden offgases are routed to an alternate bed while the saturated carbon bed is regenerated.

Regeneration of the carbon bed is accomplished by heating the bed or applying vacuum to draw off the adsorbed VOC. Heat (the heat of adsorption) is given up on adsorption and required for desorption. Low pressure steam (4) is frequently used as a heat source to strip the adsorbent of VOC. The steam-laden vapors are then sent to a condenser (5) and subsequently to some type of solvent separation system (6). The regenerated bed is put back into active service while the saturated bed is purged of organics. The regeneration process may be repeated numerous times, but eventually the carbon must be replaced.

4.1.3.2 Adsorption Control Efficiency. Many modern, well-designed systems achieve 95 percent efficiency for some chemicals.¹⁹ Higher adsorption system efficiencies are achievable, but the addition of the carbon beds necessary to reach these higher efficiencies will add to system cost. The VOC removal efficiency of an adsorption system is dependent upon the physical properties of the compounds present in the offgas, the gas stream characteristics, and the physical properties of the adsorbent.

Gas temperature, pressure and velocity are important in determining adsorption efficiency. The adsorption rate in the bed decreases sharply when gas temperatures are above 38°C (100°F).^{20,21} High temperature increases the kinetic energy of the gas molecules causing them to overcome van der Waals forces. Under these conditions, the VOC are not retained on the surface of the carbon. Increasing system pressure generally will improve VOC capture efficiency; however, care must be taken to prevent solvent condensation on the carbon surface that will decrease efficiency and subsequently may cause a fire hazard. The gas velocity entering the carbon bed must be low enough to allow time for adsorption to take place. The required depth of the bed for a given compound, therefore, is directly proportional to the carbon granule size and porosity and to the gas stream velocity (i.e., bed depth must increase as the gas velocity increases for a given carbon type).

4.1.3.3 Applicability of Adsorption. Although carbon adsorption is an excellent method for recovering some valuable process chemicals, there are no process units in the EDP where adsorbers are used. Adsorption systems are rarely used on reactor process vent streams because process vent stream conditions are not well-suited for the effective use of carbon adsorption. Some characteristics of SOCM I reactor process vent streams that make them unsuitable for effective use of carbon adsorption are: (1) high VOC concentrations (which can "flood" carbon surfaces), (2) very high or very low molecular weight compounds (which desorb or adsorb with difficulty, respectively), and (3) mixtures of high and low boiling point VOC (which can differentially desorb or adsorb). The range of organic concentration to which carbon adsorption can be applied is from a few parts per million (by volume) to concentrations of several percent.²² Process vent stream data in the EDP indicate that most streams have either very low VOC contents (less than 1 percent) or much higher VOC contents (15 to 60 percent and above). Adsorbing VOC from process vent streams with high organic concentrations may result in excessive temperature rise in the carbon bed due to the

accumulated heat of adsorption of the VOC loading. However, a high organic concentration can be diluted to a concentration low enough for the application of a carbon adsorption system.

For effective adsorption, the molecular weight of the compounds to be adsorbed should be in the range of 45 to 130 gm/gm-mole. Accordingly, carbon adsorption may not be an effective control technique for compounds with low molecular weights (below 45 gm/gm-mole) owing to their smaller attractive forces or for high molecular weight compounds (~130 gm/gm-mole) that adsorb so strongly to the carbon bed that they are not easily removed.²³ Properly operated adsorption systems can be very effective for homogeneous offgas streams; but adsorption systems can experience operating problems with a multicomponent system containing a mixture of light and heavy hydrocarbons. The lighter organics tend to be displaced by the heavier (higher boiling) components, resulting in greatly reduced system efficiency.²⁴ Vent stream data from the EDP indicate some reactor process vent streams have mixtures of light and heavy organics.

4.2 COMBUSTION CONTROL DEVICES

Combustion control devices alter the chemical structure of the VOC. Combustion is complete if all VOC are converted to carbon dioxide and water. Incomplete combustion results in some of the VOC being unaltered or being converted to other organic compounds such as aldehydes or acids.

The combustion control devices discussed in the following four sections include flares, thermal incinerators, catalytic oxidizers, and boilers and process heaters. Each device is discussed separately with respect to its operation, destruction efficiency, and applicability to reactor process vent streams. Many combustion devices are widely applied, especially where VOC control of process vent streams is mandated by current regulations and where substantial energy recovery potential exists for a particular process vent stream. For the 66 units identified in the EDP that have reactor process vent streams, 13 use incinerators, 11 use flares, 7 use boilers, and 5 use process heaters to control VOC prior to atmospheric discharge of the process vent stream. None use catalytic oxidizers.

4.2.1 Flares

4.2.1.1 Flare Process Description. Flaring is an open combustion process in which the oxygen required for combustion is provided by the air around the flame. Good combustion in a flare is governed by flame temperature, residence time of components in the combustion zone, turbulent mixing of the components to complete the oxidation reaction, and the amount of oxygen available for free radical formation.

Kalcevic presents a detailed discussion of different types of flares, flare design and operating considerations, as well as a method for estimating capital and operating costs for flares.²⁵ The basic elements of an elevated flare system are shown in Figure 4-4. Process offgases are sent to the flare through the collection header (1). The offgases entering the

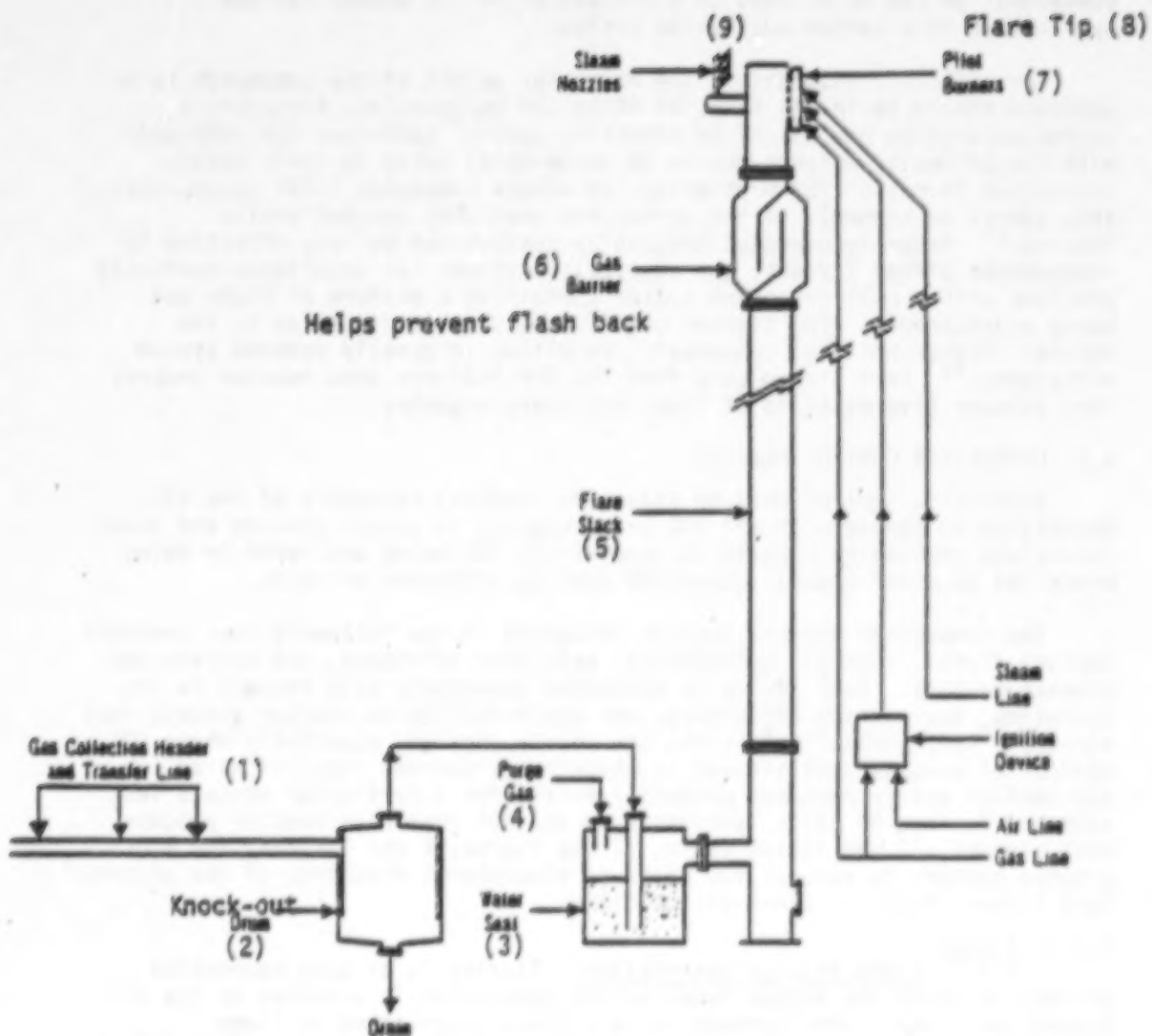


Figure 4-4. Steam-assisted elevated flare system.

header can vary widely in volumetric flow rate, moisture content, VOC concentration, and heat value. The knock-out drum (2) removes water or hydrocarbon droplets that could extinguish the flame or cause irregular combustion. Offgases are usually passed through a water seal (3) before going to the flare. This prevents possible flame flashbacks, caused when the offgas flow to the flare is too low and the flame front pulls down into the stack.

Purge gas (N_2 , CO_2 , or natural gas) (4) also helps to prevent flashback in the flare stack (5) caused by low offgas flow. The total volumetric flow to the flame must be carefully controlled to prevent low flow flashback problems and to avoid flame instability. A gas barrier (6) or a stack seal is sometimes used just below the flare head to impede the flow of air into the flare gas network.

The VOC stream enters at the base of the flame where it is heated by already burning fuel and pilot burners (7) at the flare tip (8). If the gas has sufficient oxygen and residence time in the flame zone it can be completely burned. A diffusion flame receives its combustion oxygen by diffusion of air into the flame from the surrounding atmosphere. The high volume of fuel flow in a flare requires more combustion air at a faster rate than simple gas diffusion can supply so flare designers add steam injection nozzles (9) to increase gas turbulence in the flame boundary zones, drawing in more combustion air and improving combustion efficiency. This steam injection promotes smokeless flare operation by minimizing the cracking reactions that form carbon. Significant disadvantages of steam usage are the increased noise and cost. The steam requirement depends on the composition of the gas flared, the steam velocity from the injection nozzle, and the tip diameter. Although some gases can be flared smokelessly without any steam, typically 0.15 to 0.5 kg of steam per kg of flare gas is required. Gases with heating values below about 8 MJ/scm (200 Btu/scf) may be flared smokelessly without steam or air assist.

Steam injection is usually controlled manually with the operator observing the flare (either directly or on a television monitor) and adding steam as required to maintain smokeless operation. Several flare manufacturers offer devices such as infrared sensors that sense flare flame characteristics and adjust the steam flow rate automatically to maintain smokeless operation.

Some elevated flares use forced air instead of steam to provide the combustion air and the mixing required for smokeless operation. These flares consist of two coaxial flow channels. The combustible gases flow in the center channel and the combustion air (provided by a fan in the bottom of the flare stack) flows in the annulus. The principal advantage of air-assisted flares is that expensive steam is not required. Air assist is rarely used on large flares because air flow is difficult to control when the gas flow is intermittent. About 0.8 hp of blower capacity is required for each 100 lb/hr of gas flared.²⁶

Ground flares are usually enclosed and have multiple burner heads that are staged to operate based on the quantity of gas released to the flare. The energy of the flared gas itself (because of the high nozzle pressure drop) is usually adequate to provide the mixing necessary for smokeless operation and air or steam assist is not required. A fence or other enclosure reduces noise and light from the flare and provides some wind protection. Ground flares are less numerous and have less capacity than elevated flares. Typically they are used to burn gas "continuously" while steam-assisted elevated flares are typically used to dispose of large amounts of gas released in emergencies.²⁷

4.2.1.2 Flare Combustion Efficiency.

4.2.1.2.1 Factors affecting flare efficiency. The flammability limits of the flared gases influence ignition stability and flame extinction. (Gases must be within their flammability limits to burn.) When flammability limits are narrow, the interior of the flame may have insufficient air for the mixture to burn. Fuels with wide limits of flammability (for instance, H_2) are therefore usually easier to burn.

The auto-ignition temperature of a fuel affects combustion because gas mixtures must be at a high enough temperature to burn. A gas with a low auto-ignition temperature will ignite and burn more easily than a gas with a high auto-ignition temperature.

The heating value of the fuel also affects the flame stability, emissions, and flame structure. A lower heating value fuel produces a cooler flame that does not favor combustion kinetics and also is more easily extinguished. The lower flame temperature will also reduce buoyant forces, which reduces mixing (especially for large flares on the verge of smoking). While low Btu content streams can be efficiently combusted, they are more likely to be inefficiently combusted because of the factors discussed above. For these reasons, VOC emissions from flares burning gases with low Btu content may be higher than those from flares that burn high Btu gases.

The density of the gas flared also affects the structure and stability of the flame through the effect on buoyancy and mixing. The velocity in many flares is very low, therefore, most of the flame structure is developed through buoyant forces as a result of the burning gas. Lighter gases therefore tend to burn better. The density of the fuel also affects the minimum purge gas required to prevent flashback and the design of the burner tip.

Poor mixing at the flare tip or poor flare maintenance can cause smoking (particulate). Fuels with high carbon to hydrogen ratios (greater than 0.35) have a greater tendency to smoke and require better mixing if they are to be burned smokelessly.

Many flare systems are currently operated in conjunction with baseload gas recovery systems. Such systems are used to recover VOC from the flare header system for reuse. Recovered VOC may be used as a feedstock in other processes or as a fuel in process heaters, boilers or other combustion

devices. When baseload gas recovery systems are applied, the flare is generally used to combust process upset and emergency gas releases that the baseload system is not designed to recover. In some cases, the operation of a baseload gas recovery system may offer an economic advantage over operation of a flare alone since sufficient quantity of useable VOC can be recovered.

4.2.1.2.2 Flare efficiency test data. This section presents a review of the flares and operating conditions used in five studies of flare combustion efficiency. Each study summarized in Table 4-1 can be found in complete form in the docket.²⁸⁻³³

Palmer experimented with a 1.3 cm (1/2-inch) ID flare head, the tip of which was located 1.2 m (4 ft) from the ground. Ethylene was flared at 15 to 76 m/s (50 to 250 ft/sec) at the exit, 0.1 to 0.6 MW (0.4×10^6 to 2.1×10^6 Btu/hr). Helium was added to the ethylene as a tracer at 1 to 3 volume percent and the effect of steam injection was investigated in some experiments. Destruction efficiency (the percent ethylene converted to some other compound) was 97.8 percent.³⁴

Siegel made the first comprehensive study of a commercial flare system. He studied burning of refinery gas on a commercial flare head manufactured by Flaregas Company. The flare gases used consisted primarily of hydrogen (45.4 to 69.3 percent by volume) and light paraffins (methane to butane). Traces of H_2S were also present in some runs. The flare was operated from 30 to 2,900 kilograms of fuel/hr (287 to 6,393 lb/hr), and the maximum heat release rate was approximately 68.96 MW (235×10^6 Btu/hr). Combustion efficiencies (the percent VOC converted to CO_2) averaged over 99 percent.³⁵

Lee and Whipple studied a bench-scale propane flare. The flare head was 5.1 cm (2 inches) in diameter with one 13/16-inch center hole surrounded by two rings of 16 1/8-inch holes, and two rings of 16 3/16-inch holes. This configuration had an open area of 57.1 percent. The velocity through the head was approximately 0.9 m/s (3 ft/sec) and the heating rate was 0.1 MW (0.3×10^6 Btu/hr). The effects of steam and crosswind were not investigated in this study. Destruction efficiencies were 99.9 percent or greater.³⁶

Howes, et al. studied two commercial flare heads at John Zink's flare test facility. The primary purpose of this test (which was sponsored by EPA) was to develop a flare testing procedure. The commercial flare heads were an air-assisted head and a Linear Relief Gas Oxidizer (LRGO) head manufactured by John Zink Company. The air-assisted flare burned 1,043 kg/hr (2,300 lb/hr) of commercial propane. The exit gas velocity based on the pipe diameter was 8.2 m/s (27 ft/sec) and the firing rate was 13 MW (44×10^6 Btu/hr). The LRGO flare consisted of 3 burner heads located 0.9 m (3 ft) apart. The 3 burners combined fired 1,905 kg/hr (4,200 lbs/hr) of natural gas. This corresponds to a firing rate of 24.5 MW (83.7×10^6 Btu/hr). Steam was not used for either flare, but the air-assisted flare head was in some trials augmented by a forced draft fan. Combustion efficiencies for both flares during normal operation were greater than 99 percent.³⁷

TABLE 4-1. FLARE EMISSION STUDIES COMPLETED BY OCTOBER 1982

Investigator	Sponsor	Flare Tip Design	References	Flared Gas	Throughput megawatts (10 ⁶ Btu/hr)	Flare Efficiency %
Palmer (1972)	E.I. du Pont	1.3 cm (0.5 inch) diameter	28	Ethylene	0.12-0.62 (0.4-2.1)	97.8->99
Lee & Whipple (1981)	Union Carbide	Discrete holes in 5 cm (2 inch) diameter cap	29	Propane	0.1 (0.3)	>99.9
Stiegel (1980)	Ph.D. Dissertation	Commercial design 70 cm (27.7 inch) diameter steam assisted	30	~50% H ₂ plus light hydrocarbons	14-52 (49-178)	>99
Howes et al. (1981)	EPA	Commercial design 15 cm (6 inch) diameter air- assisted	31	Propane	13 (44)	>99
		Commercial design H.P. 3 tips @ 10 cm (4 inch) diameter		Natural Gas	8.2 (28)	>99
McDaniel et al. (1982)	CMA-EPA	Commercial design 10 cm (4 inch) diameter	32	Propylene	0.003-17 (0.01-57)	83-99.9

SOURCE: Reference 33

A detailed review of all four studies was done by Joseph, et al. in January 1982.³⁸ A fifth study³⁹ determined the influence on flare performance of mixing, Btu content and gas flow velocity. A steam-assisted flare was tested at the John Zink facility using the procedures developed by Howes. The test was sponsored by the Chemical Manufacturers Association (CMA) with the cooperation and support of EPA. All of the tests were with an 80 percent propylene, 20 percent propane mixture diluted as required with nitrogen to give different heat content values. This was the first work which determined flare efficiencies at a variety of "nonideal" conditions where lower efficiencies had been predicted. All previous tests were of flares which burned gases which were very easily combustible and did not tend to soot (i.e., they tended to burn smokelessly). This was also the first test which used the sampling and chemical analysis methods developed for EPA by Howes. The steam-assisted flare was tested with exit flow velocities ranging up to about 18.3 m/s (60 ft/sec), with heat contents from 11 to 84 MJ/scm (300 to 2,200 Btu/scf) and with steam to gas (weight) ratios varying from 0 (no steam) to 6.86. Air-assisted flares were tested with fuel gas heat contents as low as 3 MJ/scm (83 Btu/scf). Flares without assist were tested as low as 8 MJ/scm (200 Btu/scf). All of these tests, except for those with very high steam to gas ratios, showed combustion efficiencies of over 98 percent. Flares with high steam to gas ratios (about 10 times more steam than that required for smokeless operation) had lower efficiencies (69 to 82 percent) when combusting 84 MJ/scm (2,200 Btu/scf) gas.

After considering the results of these five studies, EPA has concluded that 98 percent combustion efficiency can be achieved by steam-assisted flares with exit flow velocities less than 18.3 m/s (60 ft/sec) and combustion gases with heat contents over 11 MJ/scm (300 Btu/scf) and by flares operated without assist with exit flow velocities less than 18.3 m/s (60 ft/sec) and burning gases with heat contents over 8 MJ/scm (200 Btu/scf). Flares are not normally operated at the very high steam to gas ratios that resulted in low efficiency in some tests because steam is expensive and operators make every effort to keep steam consumption low. Flares with high steam rates are also noisy and may be a neighborhood nuisance.

Another study was performed by the Energy and Environmental Research Corporation for EPA in order to investigate the VOC destruction efficiency of flares at gas exit velocities greater than 60 ft/sec and 300 Btu/scf heating value. Based on this study, EPA concluded that steam-assisted and nonassisted flares that are designed and operated with an exit velocity less than 122 m/sec (400 ft/sec) can achieve and maintain a 98 percent destruction efficiency if the heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf). A report of this study is included in the docket.⁶³

The EPA has a program under way to determine more exactly the efficiencies of flares used in the petroleum refining industry/SOCMI and a flare test facility has been constructed. The combustion efficiency of four

flares (1 1/2 inches to 12 inches ID) will be determined and the effect on efficiency of flare operating parameters, weather factors, and fuel composition will be established.

4.2.1.3 Applicability of Flares. About 75 percent of the organic chemical plants are estimated to have a flare.⁴⁰ Flares are usually designed to control the normal operating vents or emergency upsets, which require release of large volumes of gases. Often, large diameter flares designed to handle emergency releases are used to control continuous vent streams from various process operations. Eleven of the 66 units (17 percent) in the EDP that have reactor process vent streams use flares to destroy VOC in those streams. Process vent stream heating values for these eleven units range generally from 7.6 to 58.8 MJ/scm (205 to 1,578 Btu/scf). In refineries, many process vents are usually combined in a common gas header that supplies fuel to boilers and process heaters. However, excess gases, fluctuations in flow in the gas line, and emergency releases are sometimes sent to a flare.

Flares have been found to be useful emission control devices. They can be used for almost any VOC stream, and can handle fluctuations in VOC concentration, flowrate, and inerts content. Some streams, such as those containing high concentrations of halogenated or sulfur-containing compounds, are not usually flared due to corrosion of the flare tip or formation of secondary pollutants (such as SO₂).

4.2.2 Thermal Incinerators

4.2.2.1 Thermal Incinerator Process Description. Any VOC heated to a high enough temperature in the presence of enough oxygen will be oxidized to carbon dioxide and water. This is the basic principle of operation of a thermal incinerator. The theoretical temperature required for thermal oxidation depends on the structure of the chemical involved. Some chemicals are oxidized at temperatures much lower than others. However, a temperature can be identified that will result in the efficient destruction of most VOC from reactor processes. All practical thermal incineration processes are influenced by residence time, mixing, and temperature. An efficient thermal incinerator system must provide:

1. A chamber temperature high enough to enable the oxidation reaction to proceed rapidly to completion;
2. Enough turbulence to obtain good mixing between the hot combustion products from the burner, combustion air, and VOC; and
3. Sufficient residence time at the chosen temperature for the oxidation reaction to reach completion.

A thermal incinerator is usually a refractory-lined chamber containing a burner (or set of burners) at one end. As shown in Figure 4-5, discrete dual fuel burners (1) and inlets for the offgas (2) and combustion air (3) are arranged in a premixing chamber (4) to mix thoroughly the hot products from the burners with the offgas air streams. The mixture of hot reacting gases then passes into the main combustion chamber (5). This section is sized to allow the mixture enough time at the elevated temperature for the oxidation reaction to reach completion (residence times of 0.3 to 1.0 second).

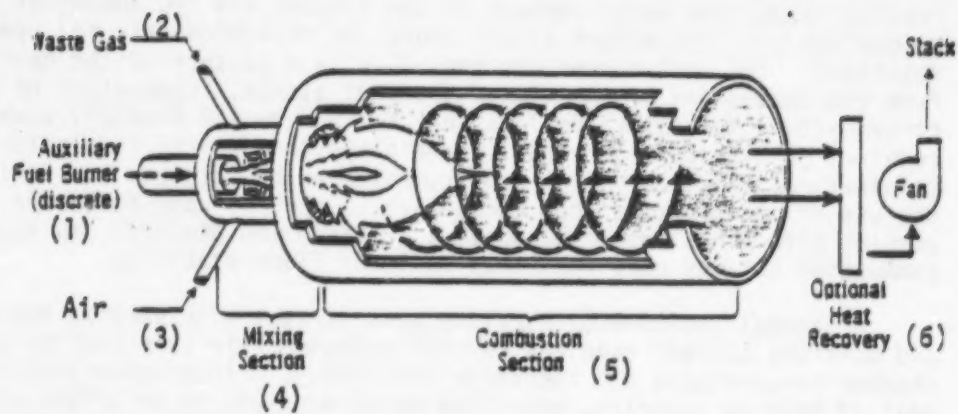


Figure 4-5. Discrete burner, thermal incinerator.

are common). Energy can then be recovered from the hot flue gases in a heat recovery section (6). Preheating of combustion air or offgas is a common mode of energy recovery; however, it is sometimes more economical to generate steam. Insurance regulations require that if the waste stream is preheated, the VOC concentration must be maintained below 25 percent of the lower explosive limit (LEL) to prevent explosion hazards.

Thermal incinerators designed specifically for VOC incineration with natural gas as the auxiliary fuel may also use a grid-type (distributed) gas burner as shown in Figure 4-6.⁴¹ The tiny gas flame jets (1) on the grid surface (2) ignite the vapors as they pass through the grid. The grid acts as a baffle for mixing the gases entering the chamber (3). This arrangement ensures burning of all vapors at lower chamber temperature and uses less fuel. This system makes possible a shorter reaction chamber yet maintains high efficiency.

Other parameters affecting incinerator performance are the vent stream heating value, the water content in the stream, and the amount of excess combustion air (the amount of air above the stoichiometric air needed for reaction). The vent stream heating value is a measure of the heat available from the combustion of the VOC in the vent stream. Combustion of vent stream with a heating value less than 1.9 MJ/scm (50 Btu/scf) usually requires burning auxiliary fuel to maintain the desired combustion temperature. Auxiliary fuel requirements can be lessened or eliminated by the use of recuperative heat exchangers to preheat combustion air. Vent streams with a heating value above 1.9 MJ/scm (50 Btu/scf) may support combustion but may need auxiliary fuel for flame stability.

A thermal incinerator handling vent streams with varying heating values and moisture content requires careful adjustment to maintain the proper chamber temperatures and operating efficiency. Since water requires a great deal of heat to vaporize, entrained water droplets in an offgas stream can increase auxiliary fuel requirements to provide the additional energy needed to vaporize the water and raise it to the combustion chamber temperature. Combustion devices are always operated with some quantity of excess air to ensure a sufficient supply of oxygen. The amount of excess air used varies with the fuel and burner type but should be kept as low as possible. Using too much excess air wastes fuel because the additional air must be heated to the combustion chamber temperature. Large amounts of excess air also increases flue gas volume and may increase the size and cost of the system. Packaged, single unit thermal incinerators can be built to control streams with flowrates in the range of 0.14 scm/sec (300 scfm) to about 24 scm/sec (50,000 scfm).

Thermal oxidizers for halogenated VOC may require additional control equipment to remove the corrosive combustion products. The flue gases are quenched to lower their temperature and are then routed through absorption equipment such as towers or liquid jet scrubbers to remove the corrosive gases. The halogenated VOC streams are usually scrubbed to prevent

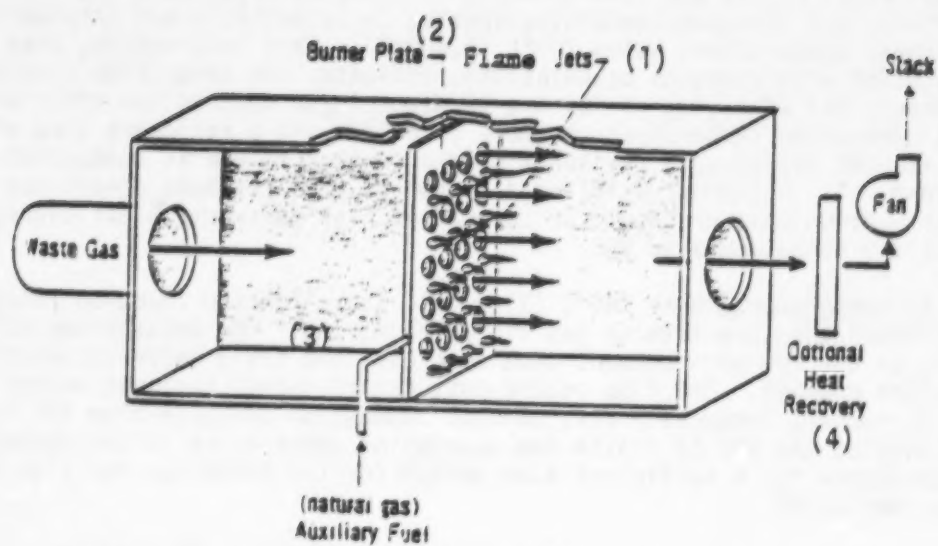


Figure 4-6. Distributed burner, thermal incinerator.

corrosion due to contact with acid gases formed during the combustion of these streams.

4.2.2.2 Thermal Incinerator Removal Efficiency. The VOC destruction efficiency of a thermal oxidizer can be affected by variations in chamber temperature, residence time, inlet VOC concentration, compound type, and flow regime (mixing). Test results show that thermal oxidizers can achieve 98 percent destruction efficiency for most VOC compounds at combustion chamber temperatures ranging from 700 to 1,300°C (1,300 to 2,370°F) and residence times of 0.5 to 1.5 seconds.⁴² These data indicate that significant variations in destruction efficiency occurred for C₁ to C₅ alkanes and olefins, aromatics (benzene, toluene, and xylene), oxygenated compounds (methyl ethyl ketone and isopropanol), chlorinated organics (vinyl chloride), and nitrogen-containing species (acrylonitrile and ethylamines) at chamber temperatures below 760°C (1,400°F). This information, used in conjunction with kinetics calculations, indicates the combustion chamber parameters for achieving at least a 98 percent VOC destruction efficiency are a combustion temperature of 870°C (1,600°F) and a residence time of 0.75 seconds (based upon residence in the chamber volume at combustion temperature). A thermal oxidizer designed to produce these conditions in the combustion chamber should be capable of high destruction efficiency for almost any nonhalogenated VOC.

At temperatures over 760°C (1,400°F), the oxidation reaction rates are much faster than the rate of gas diffusion mixing. The destruction efficiency of the VOC then becomes dependent upon the fluid mechanics within the oxidation chamber. The flow regime must assure rapid, thorough mixing of the VOC stream, combustion air, and hot combustion products from the burner. This enables the VOC to attain the combustion temperature in the presence of enough oxygen for a sufficient time period for the oxidation reaction to reach completion.

Based upon studies of thermal oxidizer efficiency, it has been concluded that 98-percent VOC destruction or a 20 ppmv compound exit concentration is achievable by all new incinerators considering current technology.⁴³ Because of much slower combustion reaction rates at lower inlet VOC concentrations, the maximum achievable VOC destruction efficiency decreases as inlet concentration decreases. Therefore, a VOC weight percentage reduction based on the mass rate of VOC exiting the control device versus the mass rate of VOC entering the device, would be appropriate for vent streams with VOC concentrations above approximately 2,000 ppmv (corresponding to 1,000 ppmv VOC in the incinerator inlet stream since air dilution is typically 1:1). For vent streams with VOC concentration below approximately 2,000 ppmv, it has been determined that an incinerator outlet concentration of 20 ppmv (by compound), or lower, is achievable by all new thermal oxidizers.⁴³ The 98 percent efficiency estimate is predicated upon thermal incinerators operated at 870°C (1,600°F) with 0.75 seconds residence time. Study results show that these conditions yield conservative estimates of costs and energy use for these type units.

4.2.2.3 Applicability of Thermal Incinerators. In terms of technical feasibility, thermal incinerators are applicable as a control device for most reactor process vent streams. They can be used for process vent streams with any VOC concentration and any type of VOC, and they can be designed to handle minor fluctuations in flows. However, excessive fluctuations in flow (i.e., process upsets) might not allow the use of incinerators and would require the use of a flare. Presence of elements such as halogens or sulfur might require some additional equipment such as scrubbers for acid gas removal. Thermal incinerators are currently used to control VOC emissions from a number of process operations including reactors and distillation operations. Thirteen of the 66 units in the EDP that have reactor process vent streams use thermal incinerator systems to control VOC in those streams. Heating values of the process vent stream for these 13 units range from 6 to 46 MJ/scm (163 to 1,228 Btu/scf).

4.2.3 Industrial Boilers and Process Heaters

Industrial boilers and process heaters can be designed to control VOC by incorporating the reactor process vent stream with the inlet fuel or by feeding the stream into the boiler or heater through a separate burner. The major distinctions between industrial boilers and process heaters are that the former produces steam usually at high temperatures while the latter raises the temperature of process streams as well as superheating steam usually at temperatures lower than an industrial boiler. The following is a process description and discussion of the applicability and efficiency of applying industrial boilers or process heaters to control VOC in process vent streams. The process description for an industrial boiler and a process heater are presented separately in the following two sections. The process descriptions focus on those aspects that relate to the use of these combustion devices as a VOC control method.

4.2.3.1 Industrial Boiler Description. Surveys of industrial boilers show that the majority of industrial boilers used in the chemical industry are of watertube design. Furthermore, over half of these boilers use natural gas as a fuel.⁴⁴ In a watertube boiler, hot combustion gases contact the outside of heat transfer tubes, which contain hot water and steam. These tubes are interconnected by a set of drums that collect and store the heated water and steam. The water tubes are of relatively small diameter, 5 cm (2.0 inches), providing rapid heat transfer, rapid response to steam demands, and relatively high thermal efficiency.⁴⁵ Energy transfer from the hot flue gases to water in the furnace water tube and drum system can be above 85 percent efficient. Additional energy can be recovered from the flue gas by preheating combustion air in an air preheater or by preheating incoming boiler feedwater in an economizer unit.

When firing natural gas, forced or natural draft burners are used to mix thoroughly the incoming fuel and combustion air. If a process vent stream is combusted in a boiler, it can be mixed with the incoming fuel or fed to the furnace through a separate burner. In general, burner design depends on the characteristics of the fuel mix (when the process vent stream and fuel are combined) or of the characteristics of the vent stream alone

(when a separate burner is used). A particular burner design, commonly known as a high intensity or vortex burner, can be effective for vent streams with low heating values (i.e., streams where a conventional burner may not be applicable). Effective combustion of low heating value streams is accomplished in a high intensity burner by passing the combustion air through a series of spin vanes to generate a strong vortex.

Furnace residence time and temperature profiles vary for industrial boilers depending on the furnace and burner configuration, fuel type, heat input, and excess air level.⁴⁶ A mathematical model has been developed that estimates the furnace residence time and temperature profiles for a variety of industrial boilers.⁴⁷ This model predicts mean furnace residence times of from 0.25 to 0.83 seconds for natural gas-fired watertube boilers in the size range from 4.4 to 44 MW (15 to 150 x 10⁶ Btu/hr). Boilers at or above the 44 MW size have residence times and are generally operated at temperatures that ensure a 98-percent VOC destruction efficiency. Furnace exit temperatures for this range of boiler sizes are at or above 1,200°C (2,200°F) with peak furnace temperatures occurring in excess of 1,540°C (2,810°F). Residence times for oil-fired boilers are similar to the natural gas-fired boilers described here.

4.2.3.2 Process Heater Description. A process heater is similar to an industrial boiler in that heat liberated by the combustion of fuels is transferred by radiation and convection to fluids contained in tubular coils. Process heaters are used in many chemical manufacturing operations discussed in Chapter 3 to drive endothermic reactions. They are also used as feed preheaters and as reboilers for some distillation operations. The fuels used in process heaters include natural gas, refinery offgases, and various grades of fuel oil. Gaseous fuels account for about 90 percent of the energy consumed by process heaters.⁴⁸

There are many variations in the design of process heaters depending on the application considered. In general, the radiant section consists of the burner(s), the firebox, and a row of tubular coils containing the process fluid. Most heaters also contain a convective section in which heat is recovered from hot combustion gases by convective heat transfer to the process fluid.

Process heater applications in the chemical industry can be broadly classified with respect to firebox temperature: (1) low firebox temperature applications such as feed preheaters and reboilers, (2) medium firebox temperature applications such as steam superheaters, and (3) high firebox temperature applications such as pyrolysis furnaces and steam-hydrocarbon reformers. Firebox temperatures within the chemical industry can range from about 400°C (750°F) for preheaters and reboilers to 1,260°C (2,300°F) for pyrolysis furnaces.

4.2.3.3 Industrial Boilers and Process Heater Control Efficiency. A boiler or process heater furnace can be compared to an incinerator where the average furnace temperature and residence time determines the combustion

efficiency. However, when a vent gas is injected as a fuel into the flame zone of a boiler or process heater, the required residence time is reduced due to the relatively high flame zone temperature. The following test data, which document the destruction efficiencies for industrial boilers and process heaters, are based on injecting the wastes identified into the flame zone of each combustion control device.

An EPA sponsored test was conducted in an effort to determine the destruction efficiency of an industrial boiler for polychlorinated biphenyls (PCB's).⁴⁹ The results of this test indicated that the PCB destruction efficiency of an oil-fired industrial boiler firing PCB-spiked oil was greater than 99 percent for a temperature range of 1,360 - 1,520°C and a range of residence time of 2-6 seconds. This efficiency was determined based on the PCB content measured by a gas chromatograph in the fuel feed and flue gas.

As discussed in previous sections, firebox temperatures for process heaters show relatively wide variations depending on the application (see Section 4.2.3.2). Tests were conducted by EPA to determine the benzene destruction efficiency of five process heaters firing a benzene offgas and natural gas mixture.⁵⁰⁻⁵² The units tested are representative of process heaters with low temperature fireboxes (reboilers) and medium temperature fireboxes (superheaters). Sampling problems occurred while testing one of these heaters, and as a result, the data for that test may not be reliable and are not presented.⁵³ The reboiler and superheater units tested showed greater than a 98 percent overall destruction efficiency for C₁ to C₆ hydrocarbons.⁵⁴ Additional tests conducted on a second superheater and a hot oil heater showed that greater than 99 percent overall destruction of C₁ to C₆ hydrocarbons occurred for both units.⁵⁵

4.2.3.4 Applicability of Industrial Boilers and Process Heaters as Control Devices. Industrial boilers and process heaters are currently used by industry to combust process vent streams from distillation operations, reactor operations, and general refinery operations. Twelve of the 66 units (18 percent) in the EDP with process vent streams use boilers or process heaters to combust reactor vent streams. Process vent stream heating values for these 12 units range from 0 to 46 MJ/scm (0 to 1,233 Btu/scf). As the profile shows, these devices are most applicable where high vent stream heat recovery potential exists.

Both boilers and process heaters are essential to the operation of a plant. As a result, only streams that are certain not to reduce the device's performance or reliability warrant use of a boiler or process heater as a combustion control device. Variations in vent stream flowrate and/or heating value could affect the heat output or flame stability of a boiler or process heater and should be considered when using these combustion devices. Performance or reliability may be affected by the presence of corrosive products in the vent stream. Since these compounds could corrode boiler or process heater materials, vent streams with a relatively high concentration of halogenated or sulfur containing compounds

are usually not combusted in boilers or process heaters. When corrosive VOC compounds are combusted, the flue gas temperature must be maintained above the acid dewpoint to prevent acid deposition and subsequent corrosion from occurring.

The introduction of a reactor process vent stream into the furnace of a boiler or heater could alter the heat transfer characteristics of the furnace. Heat transfer characteristics are dependent on the flowrate, heating value, and elemental composition of the process vent stream, and the size and type of heat generating unit being used. Often, there is no significant alteration of the heat transfer, and the organic content of the process vent stream can in some cases lead to a reduction in the amount of fuel required to achieve the desired heat production. In other cases, the change in heat transfer characteristics after introduction of a process vent stream may affect the performance of the heat generating unit, and increase fuel requirements. For some process vent streams there may be potential safety problems associated with ducting reactor process vents to a boiler or process heater. Variation in the flowrate and organic content of the vent stream could, in some cases, lead to explosive mixtures within a boiler furnace. Flame fluttering within the furnace could also result from variations in the process vent stream characteristics. Precautionary measures should be considered in these situations.

When a boiler or process heater is applicable and available, they are excellent control devices since they can provide at least 98 percent destruction of VOC. In addition, near complete recovery of the vent stream heat content is possible. However, both devices must operate continuously and concurrently with the pollution source unless an alternate control strategy is available in the event that the heat generating capacity of either unit is not required and is shut down.

4.2.4 Catalytic Oxidizer

4.2.4.1 Catalytic Oxidizer Process Description. Catalytic oxidation is the fourth major combustion technique examined for VOC emission control. A catalyst increases the rate of chemical reaction without becoming permanently altered itself. Catalysts for catalytic oxidation cause the oxidizing reaction to proceed at a lower temperature than is required for thermal oxidation. These units can also operate well at VOC concentrations below the lower explosive limit, which is a distinct advantage for some offgas streams. Combustion catalysts include platinum and platinum alloys, copper oxide, chromium, and cobalt.⁵⁶ These are deposited in thin layers on inert substrates to provide for maximum surface area between the catalyst and the VOC stream.

A schematic of a catalytic oxidation unit is shown in Figure 4-7. The waste gas (1) is introduced into a mixing chamber (3) where it is heated to about 316°C (600°F) by contact with the hot combustion products from auxiliary burners (2). The heated mixture is then passed through the catalyst bed (4). Oxygen and VOC migrate to the catalyst surface by gas diffusion and are adsorbed in the pores of the catalyst. The oxidation

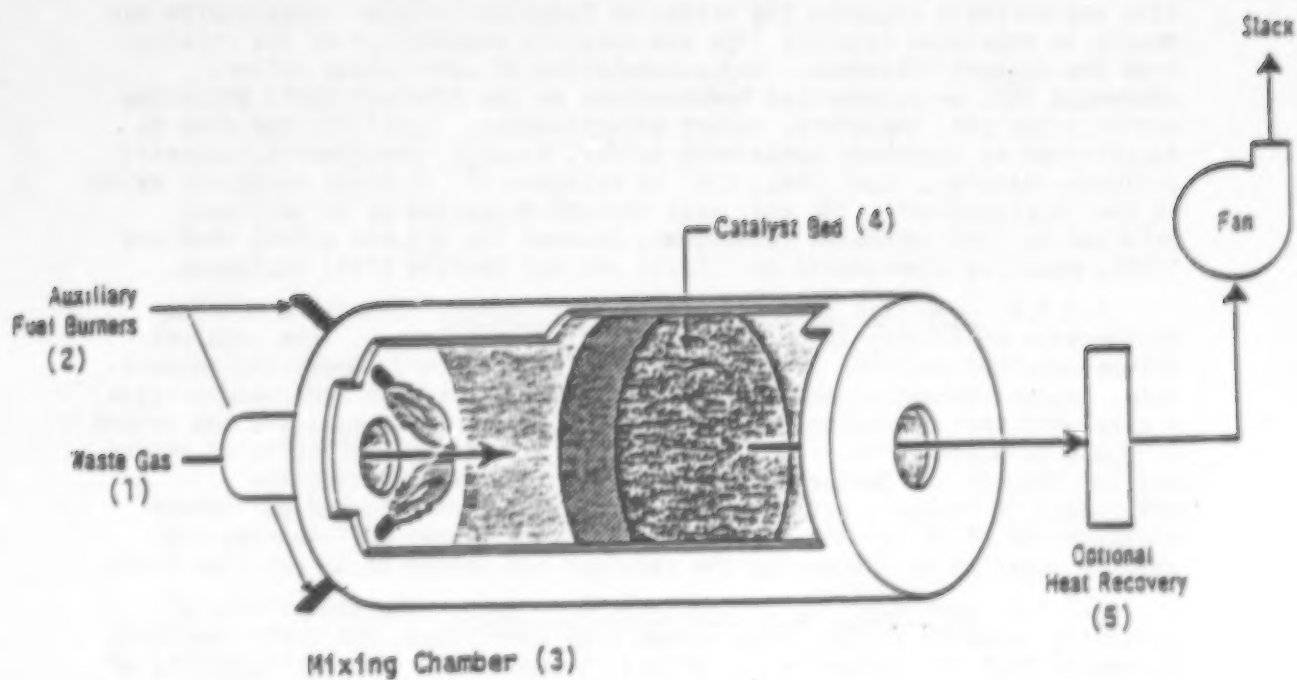


Figure 4-7. Catalytic oxidizer.

reaction takes place at these active sites. Reaction products are desorbed from the active sites and transferred by diffusion back into the waste gas.⁵⁷ The combusted gas may then be passed through a waste heat recovery device (5) before exhausting into the atmosphere.

The operating temperature of combustion catalysts usually ranges from 316 to 650°C (600 to 1,200°F). Lower temperatures may result in slowing down and possibly stopping the oxidation reaction. Higher temperatures may result in shortened catalyst life and possibly evaporation of the catalyst from the support substrate. Any accumulation of particulate matter, condensed VOC, or polymerized hydrocarbons on the catalyst could block the active sites and, therefore, reduce effectiveness. Catalysts can also be deactivated by compounds containing sulfur, bismuth, phosphorous, arsenic, antimony, mercury, lead, zinc, tin, or halogens.⁵⁸ If these compounds exist in the catalytic unit, VOC will pass through unreacted or be partially oxidized to form compounds (aldehydes, ketones and organic acids) that are highly reactive atmospheric pollutants and can corrode plant equipment.

4.2.4.2 Catalytic Oxidizer Control Efficiency. Catalytic oxidizer destruction efficiency is dependent on the space velocity, (the catalyst volume required per unit volume gas processed per hour), operating temperature, oxygen concentration, and waste gas VOC composition and concentration. A catalytic unit operating at about 450°C (840°F) with a catalyst bed volume of 0.014 to 0.057 m³ (0.5 to 2 ft³) per 0.47 scm/sec (1,000 scfm) of offgas passing through the device can achieve 95 percent VOC destruction efficiency.⁵⁹ However, catalytic oxidizers have been reported to achieve efficiencies of 98 percent or greater.⁶⁰ These higher efficiencies are usually obtained by increasing the catalyst bed volume to offgas flow ratio.

4.2.4.3 Applicability of Catalytic Oxidizers. The sensitivity of catalytic oxidizer to VOC inlet stream flow conditions, and their inability to handle high VOC concentration offgas streams, limit the applicability of catalytic units for control of VOC from many processes. Some catalytic units, however, have operated successfully on reactor process vent streams from air oxidation processes.⁶¹

4.3 SUMMARY

The two general classifications of VOC control techniques discussed in the preceding sections are noncombustion and combustion control devices. This section summarizes the major points regarding control device applicability and performance.

The noncombustion control devices discussed include adsorbers, absorbers, and condensers. In general, although noncombustion devices are widely applied in the industry, no one device is universally applicable to reactor vent streams because many restrictions exist to applying these devices across a broad category of reactor process vent streams. For example, adsorbers may not always be applicable to vent streams with: (1) high VOC concentrations, (2) low molecular weight, and (3) mixtures of low and high molecular weight compounds. These conditions exist in many

reactor process vent streams. Absorbers are generally not applied to streams with VOC concentrations below 200 to 300 ppmv, while condensers are not well suited for application to vent streams containing low boiling point VOC or to vent streams with large inert concentrations. Information in the EDP shows that 30 percent of the units with reactor process vent streams use condenser and/or absorbers to recover VOC. No units in the EDP use adsorbers. Control efficiencies for the noncombustion devices considered vary from 50 to 95 percent for condensers and absorbers and up to 95 percent for adsorbers.

The combustion control devices considered include flares, industrial boilers, process heaters, thermal incinerators, and catalytic oxidizers. With the exception of catalytic units, these devices are applicable to a wide variety of process vent stream characteristics and can achieve at least 98 percent destruction efficiency. Combustion devices are generally capable of adapting to moderate changes in process vent stream flow rate and VOC concentration, while control efficiency is not greatly affected by the type of VOC present. This is generally not the case with noncombustion control devices. In general, combustion control devices may require additional fuel - except in some cases where boilers or process heaters are applied and the energy content of the vent stream is recovered. However, because boilers and process heaters are important in the operation of a chemical plant, process vent streams that will not reduce boiler or process heater performance and reliability warrant use of these systems. Application of a scrubber prior to atmospheric discharge may be required when process vent streams containing high concentrations of halogenated or sulfonated compounds are combusted in an enclosed combustion device. In addition, the presence of high concentrations of corrosive halogenated or sulfonated compounds may preclude the use of flares because of possible flare tip corrosion and may preclude the use of boilers and process heaters because of potential internal boiler corrosion.⁶² In addition, the presence of a halogen acid, such as HCl, in the atmosphere may cause adverse health effects and equipment corrosion.

The EDP shows that all of the combustion devices are applied to process vent streams with heating values of greater than about 9.3 MJ/scm (250 Btu/scf). This indicates that combustion is typically applied to streams that do not require make-up fuel and/or that have a relatively high energy recovery potential.

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5. MODIFICATIONS AND RECONSTRUCTIONS

The reactor processes NSPS affects new reactor process units and existing reactor process units that have been modified or reconstructed (in accordance with the Code of Federal Regulations Title 40, Sections 60.14 and 60.15; 40 CFR 60.14 and 60.15). An existing facility is defined in 40 CFR 60.2 as a facility of the type for which standards of performance have been promulgated and the construction or modifications of which has begun prior to the proposal date of the applicable NSPS standards. This chapter identifies typical or possible changes to reactor processes in synthetic organic chemical manufacturing plants that could be deemed modifications or reconstructions.

5.1 MODIFICATION

"Modification" is defined in 40 CFR 60.14(a) as any physical or operational change of an existing facility that increases the emission rate of any pollutant to which a standard applies.¹ Exceptions to this definition are presented in paragraph (e) of Section 60.14. These exceptions are:

1. Routine maintenance, repair, and replacement;
2. An increase in the production rate not requiring a capital expenditure as defined in Section 60.2(bb);
3. An increase in the hours of operation;
4. Use of an alternative fuel or raw material if prior to the standard the existing facility was designed to accommodate that alternate fuel or raw material;
5. The addition or use of any system or device whose primary function is the reduction of air pollutants, except when a system is removed or replaced by a system considered to be less efficient; and
6. Relocation or change in ownership.

If any modification is made to the operation of an existing facility that results in an increased emission rate for each pollutant to which a standard applies, the facility becomes an affected facility under the provisions of Section 60.14.

The reactor process affected facility is defined as the recovery system and all reactors that discharge their vent streams into that recovery system. Such a recovery system could consist of an individual series or train of reactor process recovery equipment along with all reactors feeding vent streams into this equipment train. Each reactor not feeding vent streams into a recovery system would constitute a separate affected facility.²

5.2 RECONSTRUCTION

Under the provisions of Section 60.15, an existing facility becomes an affected facility upon reconstruction, regardless of changes in pollutant emission rates.³ Reconstruction is considered to occur upon the replacement of components in the facility if the fixed capital cost of the new component exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility to comply with the applicable standards of performance. The final judgment on what replacement constitutes reconstruction and when it is technologically and economically feasible to comply with the applicable standards of performance is made by the Administrator. The Administrator's determinations are made on the following bases:

1. Comparison of the fixed capital costs of the replacement components and a newly constructed comparable facility;
2. Comparison of the estimated life of the facility after the replacements and the life of a comparable entirely new facility;
3. The extent to which the components being replaced cause or contribute to the emissions from the facility; and
4. Any economic or technical limitations on compliance with applicable standards of performance that are inherent in the proposed replacements.

The purpose of this provision is to prevent an owner or operator from perpetuating an existing facility by replacing all but vestigial components, support structures, frames, housing, etc., rather than totally replacing the facility in order to avoid applicability to an NSPS. In accordance with Section 60.5, EPA will, upon request, determine if the action taken constitutes construction (including reconstruction).

5.3 EXAMPLES OF MODIFICATIONS AND RECONSTRUCTIONS AT EXISTING REACTOR FACILITIES

5.3.1 General Examples

Suppose a hypothetical chemical plant is producing chemical Y in an existing reactor facility consisting of three reactors all with vent streams routed to a common recovery system. To accommodate increased demand for chemical Y, the owners decided to add a fourth reactor to the facility and duct the additional vent stream to the existing recovery system. The VOC emissions from the added reactor and the existing reactors (i.e., the total discharge from the existing recovery system) would be subject to the provisions of the standard if the existing facility emissions increased as a result of the operation of the additional reactor (constituting a modification). Likewise, if one of the three existing reactors was replaced with a new larger reactor, the VOC emissions discharged from the common recovery system would also be subject to the standards if emissions increased (constituting a modification). If the capital cost of the replaced components - in this case, one larger-sized reactor - was greater than 50 percent of the cost of a new facility (i.e., 50 percent of the cost of an entirely new facility composed of three reactors and the recovery system),

the larger reactor could constitute a reconstruction and all reactors would become affected. If a company chooses to retire antiquated reactors at an existing facility and replace them with entirely new reactors venting to the existing recovery system at the same site, this change could constitute a reconstruction if the capital cost of replacement exceeds 50 percent of a new facility cost.

5.3.2 Specific Examples

The general types of modifications and reconstructions that are most likely to occur at existing facilities are feedstock or reactant substitution where the facility was not designed to use that feedstock or reactant, reactor additions, process and/or equipment changes, and combinations of the above. Individual reactor replacements at multiple reactor facilities are not expected to occur since reactors are generally designed to last the lifetime of the process unit. If reactors at multiple reactor facilities are replaced it is expected that all will be replaced at the same time in order to accommodate a process change or because of fires or explosions.

If any of these examples results in the VOC emissions increasing from the existing facility, this would constitute a modification. However, if components of an existing facility are replaced and the costs of the replacement components exceed 50 percent of the cost of a new facility, it could be considered a reconstruction even if an emissions increase did not occur.

Feedstock and reactant substitution is dictated by economics and by the availability of a substitute feedstock or reactant. Over 50 percent of the 173 chemicals considered can be manufactured from two or more different feedstocks.⁴ For example, cyclohexanone can be manufactured using either phenol or cyclohexanol as the feedstock. Although use of cyclohexanol has predominated in the industry in the past, at least one facility in the EDP has changed from using cyclohexanol to phenol. This feedstock substitution required the addition of a hydrogenation section to the existing cyclohexanone reactor system. As this example illustrates, a feedstock or reactant change may result in a significant alteration to process equipment. If equipment is replaced to accommodate the new feedstock and if substantial capital investment is required (more than 50 percent of the cost of an entirely new facility), this may be considered a reconstruction regardless of any change in emissions. Depending upon the specific process, if an alteration of a reactor process to accommodate the new feedstock causes an increase in emissions from the existing facility, the change constitutes a modification. If, however, the existing facility was designed to accommodate the substituted feedstock, even though emissions increase at the existing facility, a modification has not occurred. (See Section 5.1, exception (4).)

Another type of feedstock substitution includes changing from a relatively pure high grade feedstock (e.g., high purity ethylene) to a lower grade feedstock (e.g., low purity ethylene). Lower grade feedstocks generally have higher concentrations of dissolved gases that may volatilize

within a reactor and become a source of increased VOC emissions from that reactor. As in the above example, this type of feedstock substitution may be considered a modification unless it could be shown that the existing facility was designed for the lower grade feedstock. Because this type of feedstock substitution is generally expected to require neither process equipment replacements nor substantial capital expenditure, it is not generally expected to be considered a reconstruction.

Process equipment changes may constitute a modification depending on whether or not an emissions increase occurs. Process equipment changes may constitute a reconstruction depending upon whether or not the cost exceeds 50 percent of the cost of an entirely new facility. Examples of process equipment changes include increasing the process unit capacity by adding more reactors or by alteration of an existing recovery system (e.g., replacing an absorber or changing from an absorber to a condenser). Based on a survey of chemical plant construction summaries for the last 5 years, a relatively large number of capacity expansions are expected to occur.⁵ If a larger reactor replaces an existing reactor for the capacity expansion, and if the replacement reactor vent stream is ducted to the existing recovery system, it is expected emissions will increase which will constitute a modification. On the other hand, whether or not emissions increase, if the cost of the replacement reactor exceeds 50 percent of the cost of a new facility, it may be considered a reconstruction. Capacity expansions may also be made by the construction of additional reactors whose vent streams may be ducted to the existing recovery system. If existing facility's VOC emissions increase, this constitutes a modification. In general, the addition of reactors is expected to be the most widespread method used to expand the capacity of existing reactor process facilities, and when this occurs an emissions increase is expected to occur.⁶

5.4 REFERENCES

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6. REGULATORY ANALYSIS

This chapter describes the regulatory alternatives developed for an analysis of a potential NSPS for reactor processes. The method used to select these alternatives and the procedures used to analyze them are described in this chapter. The environmental and energy impacts, and the cost impacts associated with each regulatory alternative are presented and discussed in Chapters 7 and 8, respectively.

In general, the regulatory alternatives examine the use of combustion devices to reduce VOC emissions from new, modified, and reconstructed reactor process units projected to come on-line between 1985 and 1990. Excluded from this analysis are all reactor process units considered under the proposed air oxidation NSPS (48 FR 48932). The use of combustion devices as control techniques is examined by considering the cost effectiveness, or TRE of control, associated with the application of combustion devices to individual process units. The TRE is a concept that has been applied previously to analyze regulatory alternatives for air oxidation processes and for distillation operations. In general, the same approach is used here, and as described later in this chapter, a TRE (or cost effectiveness) cutoff value constitutes a regulatory alternative.

Section 6.1 presents a discussion of the basic assumptions and general framework associated with the regulatory analysis and Section 6.2 identifies the VOC control techniques considered under each regulatory alternative. Section 6.3 describes the individual reactor process units considered as candidates for the addition of VOC controls and describes how VOC controls are applied to these process units under the regulatory alternatives.

6.1 OVERVIEW OF THE REGULATORY ANALYSIS

The Clean Air Act (CAA) directs EPA to develop standards of performance for categories of new stationary sources of air pollution. A priority list of source categories has been prepared for which standards must be considered.^{1,2} Typically, the listed source categories are limited to single industries that utilize one or two processes to manufacture specific products. For such a case, one or more model plants are generally designed to illustrate the emissions and control device requirements of typical new sources within that industry. Projections of new emission sources for these model plants are made and then used to analyze the economic, energy, and environmental impacts of the regulatory alternatives. The regulatory alternatives are generally based on the use of several applicable control devices that may have different control efficiencies, costs, and energy requirements. The results of such a regulatory analysis permit selection of

a regulatory alternative that reflects the greatest emissions reduction achievable (considering costs) through application of the BDT for continuous emission reduction. The selection process also includes consideration of any nonair quality health, environmental, and energy impacts.

The traditional model plant approach described above is not used here because of the large number of different reactor processes involved in this source category and the complexity and diversity of the SOCM. The development and analysis of individual regulatory alternatives requiring different control technologies and emission levels for each of the chemicals and reaction types considered would be unreasonably time-consuming and resource-intensive.

The approach used here is to develop regulatory alternatives based on applying controls that have the potential to provide the basis for selecting BDT for new, modified, and reconstructed reactor process units. In Essex Chemical v. Ruckleshaus,³ BDT was defined as follows: "An adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way." In this analysis, control systems are selected that are "reasonably reliable" and "reasonably efficient" while the "economic and environmental costs" are examined through the use of various regulatory alternatives.

Control technologies used in the SOCM are discussed in Chapter 4. Combustion is the control technology chosen for the regulatory analysis since it meets the criteria set forth by the court and is applicable to all reactor process vents. Other types of controls, such as condensers, absorbers, and adsorbers can be used on individual reactor process units, but their application is so site-specific that they cannot be analyzed under a generic standard approach (i.e., applied to broad categories of reactor processes for analysis). Furthermore, combustion devices achieve higher VOC control efficiency than all other currently demonstrated control technologies at a reasonable cost. Boilers, process heaters, flares, thermal incinerators, and catalytic oxidizers are the five major types of combustion devices. As noted in Chapter 4, all are capable under certain conditions of achieving at least 98-weight-percent reduction of VOC emissions.

6.2. SELECTION OF THE COMBUSTION CONTROL TECHNIQUES USED IN THE REGULATORY ANALYSIS

As mentioned in Chapter 3, reactor process vent streams may contain halogenated or nonhalogenated VOC. The distinction between these two classes of vent streams is important in the choice of a VOC control technology. As indicated in the previous section and discussed in Chapter 4, emission reductions of 98-weight-percent are possible with five types of combustion controls (boilers, process heaters, catalytic oxidizers, flares, and incinerators). For nonhalogenated streams, any of these controls may be generally applicable, but for halogenated streams, only incinerators are applicable.

In this regulatory analysis, for each process unit in either class of vent stream (halogenated or nonhalogenated), the control technology that is least expensive, at least 98-weight-percent efficient, and applicable for the process unit is selected, and the cumulative industry impacts are summed over all process units. For halogenated vent streams, the least expensive, 98-weight-percent efficient, and applicable control technology is an incinerator with flue gas scrubbing. For nonhalogenated streams, a flare may achieve the same (98-weight-percent) efficiency as any other combustion control. Furthermore, flares are usually less expensive than incinerators although for some streams (high flow and low heating value) this is not always the case. For this reason, both flares and thermal incinerators are considered applicable to nonhalogenated vent streams, and the cost of both is considered when analyzing the regulatory alternatives. Boilers, process heaters, and catalytic oxidizers, are not applicable to many types of reactor process vent streams; stream-specific characteristics could reduce their VOC reduction efficiency or applicability. Therefore, these devices are not included in the regulatory analyses because their use in industry is not possible to predict consistently. In actual practice any device that achieves a 98-weight-percent VOC emission reduction may be used. For this regulatory analysis of the overall impact of VOC controls on the reactor processes portion of the SOCM I flares and incinerators are selected because they are 98-weight-percent efficient and most broadly applicable to reactor processes.

Although flares and incinerators have been selected as the control technology applicable to all reactor processes, they may not be the most cost-effective application in all cases. Because process vent stream characteristics vary widely, both the control cost per unit emissions reduction and the environmental impacts of applying these controls may also vary widely. Therefore, it is possible that for some process units the cost of applying controls would be so large and the emission reduction so small that flares and incinerators may not be cost effective.⁴ The possibility of not requiring combustion for some reactor process units is consistent with Section 111 of the CAA, which permits distinction among classes, types, and sizes within source categories when establishing control requirements with an NSPS.⁵ In addition, such an analysis for the similar distillation and air oxidation standards showed that some streams were not cost effective to control.

6.3 DEVELOPMENT OF REGULATORY ALTERNATIVES

6.3.1 Introduction and Summary

Regulatory alternatives are selected to examine the environmental, energy, and cost impacts associated with applying thermal incinerators and flares to control VOC emissions from new, modified, and reconstructed reactor process units. The reactor process units examined include:

(1) units that are projected to be newly constructed during the 5-year period following proposal of the NSPS (1985-1990), and (2) existing units that are projected to be modified or reconstructed during the same time frame. In the regulatory analysis, TRE values are determined for each of

these two types of process units. For an individual process unit, the TRE value is the annual cost of combustion control divided by the annual emission reduction. Because each process unit is likely to have a different TRE value, a range of values exists for the set of new, modified, and reconstructed process units examined. Regulatory alternatives are defined by specific TRE cutoff values. An analysis of each alternative is accomplished by adding the impacts associated with all process units having TRE values at or below the TRE cutoff for that specific alternative.

The remainder of this chapter presents a detailed discussion of the regulatory alternatives. First, a general process unit description is presented and the projected number and capacity of new, modified, and reconstructed reactor process units are identified and discussed briefly. Second, the estimated process vent stream characteristics for each of these units are presented and discussed in more detail. Finally, the assumptions used in applying VOC controls to individual process units to form regulatory alternatives are discussed.

6.3.2 Characteristics of the New, Modified, and Reconstructed Reactor Process Units Included in the Regulatory Analysis

This section describes the reactor process units included in the regulatory analysis. The number, type, and capacity of all new, modified, and reconstructed process units included in the regulatory analysis are identified and the process vent stream characteristics associated with each are presented. A general description of a process unit is also presented as discussed in the next section.

6.3.2.1 General Process Unit Definition and Description. As described in Chapter 5, a process unit is defined as one or more combinations of reactors and product recovery systems each manufacturing the same organic compound at a common site. In the regulatory analysis, various regulatory alternatives are examined by estimating the impacts of those alternatives on individual reactor process units. It should be noted that a reactor process unit is not necessarily the same as a reactor affected facility; and that under an NSPS, it is the reactor facility that is subject to the provisions of the standards and may be required to control VOC emissions. The significance of the use of process units in this analysis is discussed below.

Process units, not reactor facilities, are used in this regulatory analysis because the information available to project the number and capacity of units lends itself to the process unit projections and not to individual reactor facility projections. Because it is possible that a small number of process units may contain more than one reactor facility, some simplifying assumptions were made for the purpose of conducting the regulatory analysis. Where multiple reactor facilities may exist within a single process unit, the vent streams from each facility within that unit are assumed to be combined and routed to a common point. Therefore, when combustion devices are applied to process units that may contain multiple

reactor facilities, only one combustion device is assumed to be used to control the combined vents from all facilities. In order to use realistic estimates of the actual cost of VOC combustion controls, the TRE calculation is based upon the less costly control (due to economies of scale) of the combined vent streams from all reactor facilities within a process unit, rather than control of each reactor facility by multiple combustion control devices. The additional cost incurred for a duplication of reactor facility control devices would be especially large for halogenated vent streams requiring incineration and offgas scrubbing.

As indicated in Chapter 3, some reactor process units in the EDP have no process vents to the atmosphere. In addition, some process units with vents currently use combustion devices as a result of existing VOC regulations or industrial practices. The regulatory analysis examines the addition of controls only to those new, modified, and reconstructed reactor process units projected to have process vents that are currently not combusted. As discussed later, these projections are based on information contained in the EDP. Process units manufacturing chemicals where reactor vents are currently combusted are assumed to continue to apply combustion devices in the absence of an NSPS (i.e., combustion control is also applied to new, modified, and reconstructed units making these chemicals at the baseline level). Emissions from process units that use combustion devices at baseline will be included in the emission estimates presented in Chapter 7 and are discussed in Chapter 3.

6.3.2.2 Number, Type, and Capacity of Process Units. This section describes the estimated number and capacity of process units that are projected to be built between 1985 and 1990 to accommodate industry growth and replacement trends in the reactor processes industry. Also presented is a description of the three types of process units that might be added to existing industry capacity.

Process units are projected to be newly constructed, modified, or reconstructed over the first 5 years of the standards' applicability (1985-1990) for two reasons. First, new process units may be built, and existing process units may be expanded - each in response to increased demand for specific chemicals. Secondly, a number of existing process units may be retired and then replaced, as they reach their estimated useful life of 20 years.

New process units may be grassroots units while capacity expansions at existing process units could be new or modified process units. Capacity expansions are assumed to occur at existing process units primarily by: (1) adding one or more reactors or increasing the size of existing reactors at an existing facility or, (2) adding one or more completely new and independent facilities in parallel to existing reactor facilities. The second example of capacity expansions are considered to be new reactor facilities. In the first example of capacity expansions, the addition of a combustion device under a regulatory alternative would result in the control of VOC emissions from both the new and existing reactors because they are

part of the same affected facility (i.e., they are assumed to share a common product recovery device). However, emission reductions from these existing reactors are not included in the regulatory analysis. This is because of the uncertainty associated with predicting specifically which existing process units will be expanded and, subsequently, with predicting the total amount of emissions that may be controlled from those existing sources. Therefore, emission reductions associated with modified process units may be underestimated in Chapter 7.

The reconstructed (or replacement) process units may include: (1) process units that have some of their components replaced such that the cost of each replacement at each reactor facility within the process unit exceeds 50 percent of the cost of a new reactor facility or, (2) process units that are completely replaced. As discussed in Chapter 5, where multiple reactors constitute an affected facility, replacement of individual reactors are not expected to occur very often such that the cost of replacement does not exceed 50 percent of the cost of a new facility. For those process units that have replaced components as described in (1), it is assumed that the addition of combustion controls under a regulatory alternative will result in the control of emissions from all reactor facilities within the process unit. Therefore, for process units that have replaced components and that may contain more than one existing reactor facility, it is assumed that all reactor facilities within that process unit are replaced. The replacement process units discussed in (2) are replacements of the antiquated existing process units, these replacements, whether at the site of the previously existing process unit or elsewhere, would be considered new facilities under an NSPS.

Based on market demand for specific chemicals and on process unit lifetimes, 56 new, modified, and reconstructed reactor process units with uncombusted vent streams are projected to come on-line over the first 5 years of the standards' applicability. These 56 process units are considered as candidates for the addition of VOC controls in the regulatory analysis. Estimates of the production capacity for each of these units are presented in Table 6-1. The following describes the assumptions used in developing the capacity projections.

Projections of production in 1985, the first year of the standards, are made in Section 9.1.6 and are used along with projected growth rates to predict production in 1990. This production figure and an assumed industry-wide capacity utilization rate of 85 percent generate the amount of total industry capacity needed in 1990 for each chemical potentially affected by the standards. In order to determine if any additional capacity is needed to accommodate this growth, estimates of existing capacity in 1985 and the amount of capacity expected to be retired in the 1985 to 1990 period are made. Capacity is required in 1990 when existing 1985 capacity, less the amount of capacity retired, is less than the total industry capacity needed in 1990 to accommodate projected 1990 production at the 85 percent utilization rate. This calculation does not distinguish between capacity

TABLE 6-1. SUMMARY OF NEW, MODIFIED, AND RECONSTRUCTED
REACTOR PROCESS UNIT CAPACITIES

Chemical Name	Process Unit Capacity		Number of Process Units
	Gg	10 ⁶ lb	
Adipic acid	236	520.0	2
Benzyl chloride	36	79.4	1
Butyl acrylate	35	77.2	1
n-Butyl acetate	23	50.7	1
t-Butyl alcohol	5	11.0	8
t-Butyl hydroperoxide	11	24.3	1
Chlorobenzene	68	150.0	1
p-Chloronitrobenzene	18	39.7	1
Cyanuric chloride	18	39.7	1
Diacetone alcohol	7	15.4	3
Diethylbenzene	18	39.7	1
2,4-(and 2,6)-Dinitrotoluene	17	37.5	1
2,4-Dinitrotoluene	80	176.0	1
Ethyl acetate	15	33.1	4
Ethyl acrylate	40	88.1	2
Ethyl benzene	318	701.0	8
Ethylene oxide	204	450.0	3
Isopropyl alcohol	206	454.0	1
Methyl methacrylate	95	209.0	4
Nitrobenzene	153	337.0	1
1-Phenylethyl hydroperoxide	18	39.7	1
Phenylpropane	18	39.7	1
Propylene oxide	322	710.0	2
Trimethylene	18	39.7	1
Vinyl acetate	193	425.0	4
Vinyl trichloride	45	99.2	1

required due to growth in demand and that required due to retirement of old process units, but rather sums these dual effects to generate one amount.

Once the total amount of required capacity in 1990 is calculated, a single process unit size is projected to be built to satisfy the requirement. A single size is preferred due to the simplicity it implies, and because more precise choices of multiple sizes are not supported by the existing database. The single size chosen is the current median size for each chemical, (Table 9-8) and all regulatory and economic impacts are scaled to this median process unit size. The median size is divided into the total amount of required capacity for each chemical, and if a remainder exists, another full median-sized process unit is projected to be built. Since the amount of required capacity is estimated based on exact utilization rate of 85 percent, adding more capacity than needed will have the effect of lowering the final capacity utilization in 1990 from 85 percent. This 85 percent figure therefore represents not the projected utilization rate for 1990, but the rate at which a firm will decide to add new capacity. Once the new capacity is added, (i.e., when projected production grows larger than 85 percent of post-retirement available capacity) then capacity utilization is anticipated to settle back down below the 85 percent level.

The singular technique for projecting the size and number of process units does not attempt to classify the process units in terms of whether or not they will be added to an existing facility or whether they will be manifested in a modification or reconstruction of a currently operating process unit. The level of precision of the existing database will not support such exact calculations. However, by choosing the single size to be the current median process unit size, a middle ground is reached on which to calculate regulatory and economic impacts.

6.3.2.3 Vent Stream Characteristics. Costs of control for the 56 process units are developed based on vent stream information (flow rates and heat contents) contained in the EDP, described in Appendix C. The procedure used here is as follows. Flow and VOC emission factors are first calculated for each process unit in the EDP by dividing the vent stream flowrate and VOC emission rate for each process unit by the process unit production capacity associated with these rates. This allows vent stream characteristics to be predicted for the 56 process units based on these "normalized" data from the EDP. Flowrate factors (in standard cubic feet per million pounds of production capacity), VOC emission factors (in pounds of VOC per million pounds of production capacity) and heat content (in Btu per standard cubic feet) from the EDP are used to calculate vent stream characteristics and subsequently, VOC control costs for those plants included in the regulatory analysis. This is done by multiplying the emission factor in Table 6-2 (derived from the EDP) by the process unit capacity in Table 6-1.

The data in Table 6-2 were taken from a more complete listing of vent stream characteristics developed from the EDP for all chemicals projected to have new, modified, or reconstructed process units built.⁶ Because data

TABLE 6-2. SUMMARY OF NEW, MODIFIED, AND RECONSTRUCTED
REACTOR PROCESS UNIT VENT STREAM CHARACTERISTICS

Chemical Name	Flow (scf/10 ⁶ lb)	Heat Value (Btu/scf)	VOC Emissions (lb/10 ⁶ lb)	Halogenated VOC
Adipic acid	3,493,738	0	0	No
Benzyl chloride	396,000	40	398	Yes
Butyl acrylate	73,000	102	20	No
n-Butyl acetate	23,360	102	20	No
t-Butyl alcohol	148,670	0	3	No
t-Butyl hydroperoxide	841,680	217	443	No
Chlorobenzene	396,000	0	386	Yes
p-Chloronitrobenzene	2,438,567	217	682	Yes
Cyanuric chloride	396,000	40	398	Yes
Diacetone alcohol	257,544	1069	8906	No
Diethylbenzene	18,043	93	42	No
2,4-(and 2,6)-Dinitrotoluene	2,482,567	217	682	No
2,4-Dinitrotoluene	4,909,582	0	10	No
Ethyl acetate	122,640	102	146	No
Ethyl acrylate	438,000	102	594	No
Ethyl benzene	18,043	93	42	No
Ethylene oxide	21,936,600	4	3900	No
Isopropyl alcohol	148,670	0	3	No
Methyl methacrylate	73,000	102	20	No
Nitrobenzene	55,551	434	1353	No
1-Phenylethyl hydroperoxide	12,676,688	2	1950	No
Phenylpropane	18,043	93	42	No
Propylene oxide	148,670	0	3	No
Trimethylene	841,680	217	443	No
Vinyl acetate	9,244	407	2	No
Vinyl trichloride	396,000	40	398	Yes

are not available in the EDP for all the chemicals that may have new, modified, or reconstructed process units built, different procedures are used to choose representative emission factors when data are lacking in the EDP. The three procedures used for all chemicals in the regulatory analysis include: (1) the chemical specific method; (2) the chemical process method (when chemical specific data are lacking); and (3) the median method (when data for a specific chemical or its process are lacking).

As its name implies, the chemical specific method uses vent stream information from actual process units in the EDP producing a particular chemical. For example, in the case of adipic acid, data are available from three process units in the EDP. Therefore, chemical specific data from the EDP can be used to estimate the vent stream characteristics of the adipic acid process units included in the regulatory analysis. For many chemicals, vent stream characteristics are available only from one unit in the EDP. For these chemicals the one EDP unit data is used. If data are available from two units in the EDP producing a particular chemical, the average vent stream characteristics for these two are used. In cases where vent stream information is available from three or more process units as in the case of adipic acid, median values are used.

The chemical process method is used when the chemical process associated with the production of a chemical is known, but chemical specific information is not available in the EDP. For example, chloronitrobenzene is a chemical produced by the chlorination process for which chemical specific information is not available in the EDP. All of the information for chemicals in the EDP produced by the same process is used to obtain representative vent stream characteristics which are then applied to those process units making chemicals where chemical-specific data are lacking in the EDP. As with the chemical specific method, in cases where process specific data is available from only one process unit in the EDP, this data is used for the process units using that process. Where data from two units is available, the average of those vent stream characteristics is used. Finally, in cases where information from three or more units is available, median values are used.

The median method is used in cases where no information is available for a specific chemical or its process in the EDP. This method incorporates all data in the EDP and includes only one set of emission factors when applied. The median method emission factors are simply the median of all the chemical process method emission factors.

The same procedures discussed here for estimating vent stream characteristics for the 56 process units are also used to estimate the baseline emissions from process units making the 22 chemicals projected to use combustion devices in the absence of an NSPS.⁷ These chemicals are discussed in Chapter 3 (Section 3.4).

6.3.3 Description of the Regulatory Alternatives

As previously mentioned, incinerators and flares have been selected as candidates for determining BDT and, therefore, as the control techniques used to analyze the regulatory alternatives. Although other combustion techniques could be used on specific vent streams, flares and thermal incinerators are chosen as BDT candidate for reactor process vent streams. Because facilities required to control VOC emissions under this NSPS did not use VOC controls previously, it is assumed for this regulatory analysis that all control devices will be newly constructed. In the regulatory analysis, the least expensive of an incinerator or a flare is applied to process units with vent streams containing nonhalogenated VOC while incinerators with flue gas scrubbing are applied to process units with vent streams containing halogenated VOC. This approach is consistent with their application in the industry.⁸

In the regulatory analysis, VOC control costs are estimated for each new, modified, and reconstructed process unit included in Table 6-1. Flare or incinerator costs are based on the costing procedures described in Chapter 8. TRE values are estimated for each process unit by dividing the annual cost of control by the annual emission reduction achieved. Incinerators and flares are assumed to achieve 98-weight-percent VOC destruction. Once TRE values are estimated for each new, modified, and reconstructed process unit, all process units are ranked by increasing TRE values.

A regulatory alternative is defined by a specific TRE cutoff value. Therefore, the proportion of all process units controlled under each alternative varies with the TRE level considered. Because fewer reactor process units would be controlled at lower TRE values, the range of alternatives examined results in increasing numbers of new, modified, and reconstructed reactor process units being controlled at higher TRE cutoff values. Alternatives range from no additional controls, i.e., the absence of an NSPS (the baseline level described in Chapter 3), to the most stringent alternative, which assumes combustion control is applied to all of the 56 new, modified, and reconstructed process units with uncombusted vent streams. The range of TRE values between these two extremes are examined in the regulatory analysis. Using results from the regulatory analysis, the number and percent of process units controlled at selected TRE cutoff values are presented in Table 6-3. These TRE levels span the range of regulatory alternatives. The national environmental and energy impacts of each alternative are presented and discussed in Chapter 7, and the national cost impacts are presented and discussed in Chapter 8.

TABLE 6-3. NUMBER AND PERCENTAGE OF PROCESS UNIT EXPECTED
TO BE CONTROLLED AT VARIOUS TRE LEVELS

TRE, \$/Mg	Percentage of Process Units Controlled	Number of Process Units Controlled
0 (Baseline)	0	0
1,200	7.	4
2,500	13.	7
5,500	16.	9
20,000	38.	21
50,000	59.	33
200,000	75.	42
500,000	82.	46
>500,000	100.	56

6.4 REFERENCES

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5. United States Congress. Clean Air Act, as amended August 1977. 42 U.S.C. et. seq. Washington, D.C. U.S. Government Printing Office. November 1977.
6. Memorandum from Cassidy, M. A. and M. A. Baviello, Radian Corporation, to Reactor Processes NSPS File. Emission Characteristics of the New, Modified, and Reconstructed Reactor Processes Units Projected to Come On-line Between 1985 - 1990. May 10, 1985.
7. Reference 6.
8. Memorandum from Read, B. S., Radian Corporation, to Reactor Processes NSPS File. Combustion Controls Used in the Emission Data Profile. May 29, 1985.

7. ENVIRONMENTAL AND ENERGY IMPACTS

This chapter presents the impacts of the regulatory alternatives on national VOC emissions and discusses other impacts on air quality, water quality, solid wastes, and energy consumption. The analysis considers both the impacts attributed directly to control devices (e.g., reduced VOC emissions) and the indirect or secondary impacts (e.g., potential aggravation of other pollutant problems through use of VOC control devices). The emphasis of the assessment is on national incremental impacts of successively more stringent regulatory alternatives.

Under the regulatory alternatives discussed in Chapter 6, combustion controls are applied to varying proportions of new, modified, and reconstructed reactor process units according to the TRE of control. TRE values are a measure of the cost effectiveness of VOC control and are expressed as the cost of control per unit of VOC emissions reduction. Incineration and flaring are the combustion techniques used as the basis of the TRE calculations.

7.1 INTRODUCTION

The analysis considers all process units projected to come on-line during the 5-year period of July 1, 1985, to July 1, 1990. These projections, which are discussed in Chapter 6 (see Table 6-1), include new grassroots process units, capacity expansions at existing process units, and all other process units that are modified or reconstructed. The circumstances that constitute new, modified, and reconstructed facilities are discussed in Chapter 5.

VOC emissions from new, modified, and reconstructed reactor process units may be generally divided into two categories for the purpose of this regulatory analysis: (1) emissions from process units that are anticipated to use combustion devices on their vent streams in the absence of an NSPS and, (2) emissions from process units that are anticipated to use no combustion devices on their vent streams in the absence of an NSPS. National emissions for the first category of process unit emissions (from combusted vent streams) will be the same as baseline under all regulatory alternatives. The second category of process unit emissions (from uncombusted vent streams) are uncontrolled at baseline and, therefore, have the potential to be controlled by the application of combustion devices. Under a regulatory alternative, combustion is applied to those uncombusted vent streams with TRE values that fall within a range of value specified in the given regulatory alternative. For example, an alternative may consist of the control of all process units with TRE values between \$0/Mg and \$1,000/Mg.

The VOC emissions reduction and other environmental and energy impacts resulting from the control of these process units are calculated as described below.

7.2 AIR POLLUTION IMPACTS

This section describes the methodology used to estimate VOC emissions reductions and other air pollution impacts associated with the regulatory alternatives. The pollution impacts presented in this section include the estimated national VOC emissions under each regulatory alternative and the emissions reduction compared to the baseline level. NO emissions resulting from the use of combustion control devices are also discussed.

7.2.1 Method of Estimating VOC Emissions and Emission Reductions

In this section, the methods of calculating emissions are discussed for new, modified, and reconstructed process units with and without combustion controls on the vent streams. Because the calculated TRE value for each process unit is used to determine which process units will be controlled under the various alternatives, this section also describes how the TRE is calculated for an individual new, modified, or reconstructed process unit.

For the first group of process units (with combustion controls at baseline), vent streams are assumed to be controlled with combustion devices under all regulatory alternatives. Similar process units for these chemicals are currently combusted under existing industry practice or as a result of existing State or Prevention of Significant Deterioration regulations. It is assumed that combustion of the vent streams from these chemical reactor processes will not change in the future. Therefore, nationwide VOC emissions for these chemicals under all regulatory alternatives are the same as emissions under the baseline alternative. Uncontrolled emissions for each process unit are calculated by multiplying the predicted volume of 1990 production for specific chemicals projected to use combustion in the absence of an NSPS (Section 9.1.2.2), by an emission factor that is derived for each chemical, expressed in terms of kilograms of VOC emitted per megagram of chemical produced (pounds of VOC emitted per million pounds of chemical produced).^{1,2} Assuming the combustion devices applied will achieve 98-weight-percent destruction, the uncontrolled emissions are multiplied by 0.02 to yield controlled emissions. Emissions for all chemicals are summed.

For the second group of process units (without combustion controls), vent streams are not projected to be combusted under existing regulations and industry practices. The following three-step approach is used to estimate these VOC emissions under each regulatory alternative. (1) For a single process unit, uncontrolled VOC emissions are calculated by multiplying the estimated production at the this process unit by an uncontrolled chemical-specific emission factor derived from the EDP. All emissions are calculated assuming a 77 percent capacity utilization of the particular process unit under examination. This is consistent with the capacity utilization used to determine annualized control costs for each unit (see Chapter 8). The sum of the emissions for each reactor process unit

constitute the uncombusted vent stream contribution to the baseline emissions. This portion of baseline emissions may be potentially reduced under an NSPS. (2) A TRE value is calculated to determine whether this process unit will be required to reduce emissions by 98-weight-percent under a given regulatory alternative. For vent streams containing nonhalogenated VOC, the TRE calculated is based on the less costly of a flare or an incinerator. For vent streams containing halogenated VOC, the TRE is based on the incinerator. A scrubber is used on the incinerator flue gas to remove corrosive by-products that result from the combustion of halogenated VOC. If a process unit can apply incineration or flaring at a TRE value that is within the range of values specified for that alternative, it is assumed to combust the vent stream. (3) If combustion is applicable under a given alternative as defined in step (2), a controlled emission factor is estimated assuming 98 percent destruction of the VOC in the vent stream. Otherwise, an uncontrolled emissions estimate, as defined in step (1), is used for that alternative.

The following discussion reviews the method of calculating TRE values; which are used to determine if individual process units are controlled under the regulatory alternatives. A TRE is calculated for each of the 56 new, modified, and reconstructed process units considered here. As discussed earlier, the TRE is the ratio of the annualized VOC control cost to the associated emissions reduction. The costs of applying incineration or flaring to individual process units are estimated using both the incinerator and flare cost algorithms discussed in Chapter 8 and the capacity and process vent stream characteristics presented in Chapter 6. Uncontrolled emissions for each new, modified, and reconstructed process unit are estimated from the vent stream characteristics presented in Chapter 6, and potential emissions reductions are determined assuming 98 percent destruction of this uncontrolled VOC.

7.2.2 VOC Emissions Impacts

The primary environmental impact of the regulatory alternatives is the reduction of VOC emissions from reactor processes. The total VOC emissions from all new, modified, and reconstructed process units under baseline is estimated to be approximately 3,300 Mg/yr (3,600 tons/yr) in 1990. About 2,400 Mg/yr (2,600 tons/yr) of these VOC emissions are from process units with vent streams where combustion is not projected to be used at baseline; while about 910 Mg/yr (1,000 tons/yr) of these VOC emissions are emitted from the outlets of combustion devices projected to be used at baseline. Thus, a maximum of 98 percent of 2,400 Mg/yr or approximately 2,300 Mg/yr (2,600 tons/yr) of VOC is available to be controlled under regulatory alternatives more stringent than baseline.

Tables 7-1 and 7-2 present the total VOC emissions and the VOC emissions reductions achieved at various regulatory alternatives. For a particular regulatory alternative, the reduction over baseline is the difference between VOC emissions at the baseline level and VOC emissions under that particular regulatory alternative. The numbers of new, modified, and reconstructed process units controlled by combustion are also shown. The

TABLE 7-1. ENVIRONMENTAL AND ENERGY IMPACTS OF THE REGULATORY ALTERNATIVES (Metric Units)

Alternative Number	Average TRE for Alternative ^b (\$/Mg)	Boundary TRE Values (\$/Mg)	Number of Units Controlled Over Baseline	National VOC Emissions (Mg/yr)	National Emission Reduction Over Baseline (Mg/yr)	Percent of Controllable Emissions Reduced ^d	National Energy Impacts Over Baseline ^e (TJ/yr)
I Baseline ^f	0	0	-	3,300	-	-	-
II	500	1,200	4	3,000	300	13	3
III	1,700	2,500	7	1,150	2,100	90	320
IV	1,800	5,500	9	1,100	2,100	91	340
V	2,100	20,000	21	990	2,300	97	390
VI	2,900	50,000	33	960	2,300	100	430
VII	3,200	200,000	42	960	2,300	100	440
VIII	3,500	500,000	46	960	2,300	100	450
IX	4,000	>500,000	56	960	2,300	100	520

^aCalculated for the fifth year of the NSPS, 1990, in 1982 dollars.

^bTRE, or total resource effectiveness, is the cost (\$) per megagram (Mg) of VOC emissions removed. Average TRE calculated as national annual cost/national emissions reduction over baseline.

^cNew, modified, or reconstructed (replacement) process units considered in the analysis of those estimated to come on-line between 1985 and 1990.

^dControllable emissions are the 2,400 Mg/yr that would be controlled at 98 percent VOC destruction efficiency (i.e., at the most stringent possible alternative, Alternative IX).

^eEnergy impacts include both fuel (natural gas) and electricity use and any heat recovery credits.

^fBaseline emissions include emissions from process units with combusted (controlled) vent streams and those with uncombusted (uncontrolled) vent streams.

TABLE 7-2. ENVIRONMENTAL AND ENERGY IMPACTS OF THE REGULATORY ALTERNATIVES (English Units)^a

Alternative Number	Average TRE for Alternative ^b (\$/Ton)	Boundary TRE Values (\$/Ton)	Number of Units Controlled Over Baseline	National VOC Emissions (Ton/yr)	National Emission Reduction Over Baseline (Ton/yr)	Percent of Controllable Emissions Reduced ^d	National Energy Impacts Over Baseline ^e (10 ⁶ Btu/yr)
I Baseline ^f	0	0	-	3,600	-	-	-
II	450	1,100	4	3,300	330	13	2.6
III	1,600	2,300	7	1,300	2,300	90	300
IV	1,600	4,500	9	1,200	2,300	91	320
V	1,900	18,000	21	1,100	2,500	97	370
VI	2,600	45,000	33	1,100	2,500	100	400
VII	2,900	190,000	42	1,100	2,500	100	410
VIII	3,200	450,000	46	1,100	2,500	100	430
IX	5,700	>450,000	56	1,100	2,500	100	490

^aCalculated for the fifth year of the NSPS, in 1982 dollars.

^bTRE, or total resource effectiveness, is the cost (\$) per ton of VOC emissions removed. Average TRE calculated as the national annual cost/national emissions reduction over baseline.

^cNew, modified, and reconstructed (replacement) process units considered in this analysis are those estimated to come on-line between 1985 and 1990.

^dControllable emissions are the 2,600 tons/yr that would be controlled if all 56 units were controlled at 98 percent VOC destruction efficiency (i.e., at the most stringent possible alternative, Alternative IX).

^eEnergy impacts include fuel and electricity use and any heat recovery credits.

^fBaseline emissions include emissions from process units with combusted (controlled) vent streams and those with uncombusted (uncontrolled) vent streams.

most stringent alternative assumes combustion control is applied to all new, modified, and reconstructed process units. Under this alternative a national VOC emissions reduction of 80 percent over baseline, or approximately 2,300 Mg/yr (2,600 tons/yr), occurs.

7.2.3 Other Effects on Air Quality

Combustion processes may produce secondary emissions, particularly nitrogen oxides (NO_x). However, overall impacts of the regulatory alternatives are expected to be relatively small because NO_x emission concentrations from incinerators and other combustion devices are generally low. Data characterizing NO_x emissions from incinerators are presented below.

The principal factors affecting the rate of NO_x formation during combustion are the amount of excess air available, the peak flame temperature, the length of time that the combustion gases are at peak temperature, and the cooling rate of the combustion products.³ Test data show that incinerator outlet concentrations of NO_x from a toluene diisocyanate process unit in the EDP were about 84 ppmv.⁴ Testing at a polymer and resin process unit using an incinerator for VOC control measured NO_x concentrations ranging from 20.2 to 38.6 ppmv.⁵ The fuels tested were mixtures of natural gas, waste gas, and/or atactic waste; incineration temperatures ranged from 980 to 1,100°C (1,600 to 2,000°F). In a series of seven sets of tests conducted at three air oxidation process units, incinerator outlet NO_x concentrations ranged from 8 to 200 ppmv.⁶ These values could increase by several orders of magnitude in a poorly designed or operated unit. Although there are conflicting data, some studies report that incineration of vent streams containing high levels of nitrogenous compounds may also result in increased NO_x emissions.⁷ In these studies, the maximum outlet NO_x concentration measured from a combustion device at a acrylonitrile (air oxidation) process unit, with a vent stream containing nitrogenous compounds, was 200 ppmv.⁸ The NO_x concentrations measured at the first four process units discussed above, where the vent streams do not contain nitrogenous compounds, range from 8 to 84 ppmv.⁹

An alternative combustion technique used in the regulatory analysis is flaring. NO_x concentrations were measured at two flares used to control hydrocarbon emissions from refinery and petrochemical processes. One flare was steam-assisted and the other air-assisted, and the heat content of the fuels ranged from 5.5 to 81 MJ/scm (146 to 2,183 Btu/scf). The measured NO_x concentrations were somewhat lower than those for incinerators, ranging from 0.4 to 8.2 ppmv. The ranges of relative NO_x emissions per unit of heat input are 7.8 to 90 g/GJ (0.018 to 0.208 lbs/10⁶ Btu) for flares.¹⁰

Although incinerators and flares were examined as combustion techniques in the regulatory analysis, process heaters may be applicable in some cases for combustion control. No NO_x data were available for process heaters used on reactor vent streams; however, most of these process heaters would use natural gas as a primary or supplemental fuel. Data on NO_x emissions from gas-fired process heaters show an average NO_x concentration of about 76 to 138 ppmv. In general, mechanical draft heaters with preheating emitted more

NO_x than furnaces without preheating and natural draft furnaces. Also, NO_x emissions were higher under typical excess air conditions (about 5.5 percent oxygen) than under low excess air conditions (about 3 percent oxygen).¹¹

In addition to NO_x emissions, combustion of halogenated VOC emissions may result in the release of halogenated combustion products to the environment. The EDP shows that most streams containing halogenated VOC would not be controlled by a flare. Incinerators are generally more capable of tolerating the corrosive effects of halogenated VOC and its combustion by-products. In addition, scrubbing can be used to remove these halogenated compounds from an incinerator's flue gas. Generally, incineration temperatures greater than 870°C (1,600°F) are required to ensure 98 percent destruction of halogenated VOC. For example, when incinerating chlorinated VOC at temperatures of 980 to 1,100°C (1,800 to 2,000°F), almost all chlorine present exists in the form of hydrogen chloride (HCl). The HCl emissions generated by thermal oxidation at these temperatures can be efficiently removed by wet scrubbing.¹² As noted earlier, the cost of the scrubber was added to the overall thermal incinerator system cost that was included in the regulatory analysis.

7.3 WATER POLLUTION IMPACTS

Control of VOC emissions using combustion does not typically result in any significant increase in wastewater discharge. That is, no water effluents are generated by the combustion device. However, the use of an incinerator/scrubber system for control of vent streams with halogenated VOC does result in slightly increased water consumption. In this type of control system, water is used to remove the acid gas contained in the incinerator outlet stream. The makeup rate for water that is purged from the system may be approximately 0.033 m³/kg (19.2 gal/lb) of halogen in the waste gas if a waste heat boiler is used prior to the scrubber or higher if no waste heat boiler is used. Vent streams smaller than 700 scfm generally don't have waste heat boilers as discussed in Chapter 8. In most cases, any increase in total process unit wastewater would be relatively small and in any case would not affect plant waste treatment or sewer capacity. More than half of the process units with vent streams containing halogenated VOC are already combusted in an incinerator at baseline. The remaining process units generally have very high TRE values and would likely not be required to use an incinerator under an NSPS. The increase in scrubber wastewater flow due to an NSPS is, therefore, projected to be quite small.

The water effluent guidelines for individual States may require that industrial sources maintain the pH of water effluent within specified limits. To meet these guidelines, the water used as a scrubbing agent may need to be neutralized prior to discharge to the plant effluent system. The scrubber effluent can be neutralized by adding caustic (NaOH) to the scrubbing water. The amount of caustic needed depends on the amount of acid gas in the incinerator flue gas. For example, approximately 1.09 kilograms (2.4 pounds) of caustic (as NaOH) are needed to neutralize one kilogram (2.2 pounds) of HCl.

The salt formed in the neutralization step must be purged from the system for proper disposal. The methods of disposal include direct waste water discharge into sewer systems, salt water bodies, brackish streams, and, on occasion, freshwater streams, sewer systems, deep well injection, and salt recovery. Use of the latter disposable method is not very widespread, and data show that most plants currently incinerating halogenated streams have state permits to dump the brine or use onsite wells to dispose of salty wastewater at a relatively low cost.¹³ It is expected that such permits would be issued to new plants as well. The increased water consumption and caustic costs were included in the projected operating costs for control of halogenated vent streams using an incinerator/scrubber system. The costs associated with the disposal of the salty wastewater were judged not to be significant in comparison to the control costs and, therefore, were not included in the projected cost impacts presented in Chapter 8.¹⁴

An alternative to brine disposal is to use the brine as feed to chlorine production. Such a use would be site specific, where there was a need for the chlorine in subsequent syntheses, and where quantities of brine either alone or in combination with other brine sources were adequate for economical production.

The use of scrubbers to remove HCl from the incinerator flue gas also has the potential to result in small increases in the quantities of organic compounds released into plant wastewater. However, only small amounts of organics are released into the scrubber wastewater; and the flow of wastewater from the scrubber is small in comparison to total plant wastewater, especially in installations where there are multiple chemical processing units using a central wastewater treatment facility. In addition, as discussed above for scrubber brine wastewater, over half of the halogenated streams in the EDP are already combusted at baseline.¹⁵ This fact combined with the generally high TRE values for process units that are projected to have uncombusted halogenated vent streams indicate that the increased incinerator scrubber wastewater flows due to this NSPS will be small. Therefore, the increase in the emission of organics in plant wastewater is not likely to be significant.

7.4 SOLID WASTE DISPOSAL IMPACTS

There are no significant solid wastes generated as a result of control by combustion. A small amount of solid waste for disposal could result if catalytic oxidation, instead of flaring or thermal incineration, were used by a facility to achieve an equivalent degree of VOC control. The solid waste would consist of spent catalyst.

7.5 ENERGY IMPACTS

The use of incineration to control VOC from reactor process vent streams can result in fuel and electricity usage. Supplemental fuel is frequently required to support combustion. Electricity is required to operate the pumps, fans, blowers and instrumentation that may be necessary to control VOC

using an incinerator or flare. Fans and blowers are needed to transport vent streams and combustion air. Pumps are necessary to circulate absorbent through scrubbers that treat corrosive offgases from incinerators combusting halogenated VOC. Fuel and energy usage requirements for incinerators and flares are discussed in detail as part of the overall cost methodology in Chapter 8.

Tables 7-1 and 7-2 present total estimated energy usage associated with each regulatory alternative. These energy values include both fuel and electricity usage estimates assuming either incineration or flaring as the combustion technique. Energy impacts under the regulatory alternatives range from about 3 to 520 TJ/yr (3 to 490 billion Btu/yr). Electricity generally accounts for less than about 2 percent of the total energy impacts, while fuel use accounts for the remainder.

In reality, other combustion devices could also be used to control some new reactor process vents. This would affect fuel usage requirements. If boilers or process heaters are used, steam can be produced and sold. This may result in net energy savings, depending on the heat recovery potential associated with a particular vent stream.

7.6 OTHER ENVIRONMENTAL IMPACTS

7.6.1 Considerations for Installing Control Equipment

Depending on the volume of process vent gas to be controlled, incinerators and flares may require a site as large as 300 feet by 300 feet for installation. Because thermal incinerators and flares use combustion with a flame to control VOC emissions, these devices must be located at a safe distance from process equipment handling flammable chemicals; otherwise, special precautions may be needed to minimize the risk of explosion or fire.

7.7 OTHER ENVIRONMENTAL CONCERNS

7.7.1 Irreversible and Irretrievable Commitment of Resources

The use of combustion devices to control VOC emissions from reactor processes usually requires the use of supplemental energy in the form of natural gas. The adverse effects of using these nonrenewable resources must be considered when evaluating the benefits of controlling the release of potentially harmful air pollutants.

The use of product recovery techniques or process modifications is another alternative to reduce VOC emissions. Control of VOC emissions using product recovery techniques might be a viable alternative to combustion control for some reactor processes. Since the reactor process vent streams containing VOC are also derived ultimately from petroleum, these product recovery techniques would result in conservation of both chemicals and fuels derived from petroleum.

7.7.2 Environmental Impact of Delayed Standards

Annual 1990 VOC emissions from reactor processes assuming current (baseline) levels of control are estimated to be 3,300 Mg/yr (3,600 tons/yr).

Under the most stringent alternative (vent streams from all 56 new, modified, and reconstructed process units are controlled by 98 percent efficient control devices) 1990 VOC emissions would be about 910 Mg/yr (1,000 tons/yr). This is an emissions reduction of about 2,300 Mg/yr (2,600 tons/yr), as shown in Tables 7-1 and 7-2. If the standard is delayed, these emission reductions would not occur, given that the most stringent alternative is adopted as the standard.

7.8 REFERENCES

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15. Reference 1.

8. COSTS

This chapter presents cost estimates for controlling VOC emissions from reactor process facilities in SOCM. Although a significant amount of time has elapsed since these cost analyses were performed, the Agency has decided not to update the cost information because it is believed that updated costs would not significantly change the impacts or the requirements of the standards. The cost impacts of each of the regulatory alternatives presented in Chapter 6 are analyzed. Two types of control systems are considered in the cost analyses: flares and thermal incinerators.

Section 8.1 includes a discussion of the design criteria for both control systems. Based on these design criteria, control costing procedures are developed. Section 8.2 includes a discussion of the capital cost basis for both systems while the annualized cost basis is discussed in Section 8.3. A comparison of the control system costs is given in Section 8.4. Finally, the national cost impacts of each of the regulatory alternatives are presented in Section 8.5, while Section 8.6 presents a discussion of the accumulated economic impacts on SOCM due to all air pollution standards.

8.1 CONTROL SYSTEM DESIGN

This section discusses the design of thermal incinerators and flares for controlling VOC emissions from reactor processes. For any reactor process vent, the design and applicability of either control system is based on the vent stream flowrate, heating value, and halogen content. Equations are used to calculate equipment size, operating parameters, caustic consumption, and utility use (natural gas, electricity, steam and water) for combusting a given vent stream.

The design of thermal incinerators is discussed in Section 8.1.1. Included in the discussion is a section defining categories of thermal incinerators that are developed for costing purposes. These categories are defined according to the presence of halogenated compounds and heating value of reactor process vent streams. A discussion of flare design is given in Section 8.1.2.

8.1.1 Thermal Incinerator Design

8.1.1.1 General Design Criteria. A thermal incinerator control system may consist of the following equipment: combustion chamber, recuperative heat exchanger, waste heat boiler, quench/scrubber system, and auxiliary equipment such as ducts, pipe rack, fans, and stack. Incinerator design equations are used to estimate the combustion chamber volume, heat exchanger surface area (for low heat content vent streams), waste heat boiler surface area (for halogenated vent stream heat recovery), auxiliary equipment sizes, and various system operating parameters. All of these estimated equipment sizes and operating parameters are used to determine the total installed capital cost as well as the annual operating and maintenance costs of the incinerator.

The combustion chamber volume is a function of the incinerator residence time, operating temperature, and flue gas flowrate. The flue gas flowrate for a specific process vent stream is determined through mass and energy balances based on the incinerator temperature, the primary and supplementary natural gas requirements, and the excess air level assumed in the flue gas stream. A design vent stream flowrate is used in designing incinerator systems. The design flowrate is 5 percent greater than the vent stream flowrate. The combustion chamber volume, incinerator temperature, furnace residence time, and other general design criteria are presented in Table 8-1 and were developed from an EPA report which was based on data supplied by vendors.¹

The smallest incinerator used in the costing procedures has a combustion chamber volume of 1.01 m³ (35.7 ft³).² Under the incinerator design criteria, an incinerator with a 1.01 m³ combustion chamber is applied to reactor process vent streams with initial process flowrates of 14.2 scm/min (500 scfm) or less. To compensate for the application of an oversized combustion chamber to streams with flowrates less than 14.2 scm/min, natural gas and air are added to maintain the desired combustion temperature and residence time. The process vent stream flowrate then equals 14.2 scm/min and the design flowrate is 5 percent greater at 14.9 scm/min (526 scfm).

Reactor processes facilities requiring an incinerator larger than 32 ft x 16 ft are assumed to use multiple smaller incinerators because they would cost less than one large incinerator. Control costs are lower for the smaller incinerators because field fabrication is not required. Incinerators larger than 32 ft x 16 ft require field fabrication, which greatly increases the costs.³

A recuperative heat exchanger is used to preheat combustion air and/or the vent stream when the vent stream heating value is insufficient to maintain the design incinerator temperature. The use of a heat exchanger reduces the amount of supplemental natural gas needed to maintain proper incinerator temperature. A heat exchanger is not applied to vent streams with heating values high enough to maintain or exceed the desired incinerator temperature or to vent streams with heating values greater than 25 percent of the typical VOC lower explosive limit (LEL) in air. This is due to the fact that raising the vent stream temperature through heat exchange could result in damage to the combustion chamber, increase NO_x production, or risk precombustion in the heat exchanger. Further, the use of heat exchangers on streams with high heating values would not provide any fuel savings. A recuperative heat exchanger is included in incinerator systems for non-halogenated vent streams with heat contents less than or equal to 0.48 MJ/scm. Further discussion on the applicability of recuperative heat exchangers is included in Section 8.1.1.2.

It is assumed that the thermal incinerator uses a quench/scrubber system for all process vent streams containing halogenated compounds. Water is used to cool the flue gases in a quench chamber before introduction to the scrubber

where water is used for acid gas removal. The acidic water resulting from waste gas scrubbing is neutralized with caustic. The quench and scrubber water and caustic requirements are determined through mass and energy balances and the general scrubber design criteria listed in Table 8-1.

For halogenated vent streams with process flowrates equal to or greater than 19.8 scm/min (700 scfm) a waste heat boiler is added after the incinerator but prior to the quench/scrubber system to obtain heat recovery through steam generation. Flue gas exiting the incinerator at 2,000°F is cooled down to 500°F upon passage through the waste heat boiler.⁴ However, waste heat boilers are not manufactured for streams with flowrates of less than 19.8 scm/min.⁵ In order to compensate for the absence of a waste heat boiler for streams with flowrates less than 19.8 scm/min, more quench water is needed to cool the gas to 500°F before it enters the scrubber for acid gas removal. Because more water is added to quench the hotter flue gas, the amount of water vapor in the gas stream increases, thus causing the gas stream volume to increase. The increased volume requires a larger scrubber than would be required if a waste heat boiler were used.⁶

In designing the thermal incinerator control system, it is assumed that all process vent streams contain no oxygen. In order to increase the rate of combustion and avoid incomplete combustion and pyrolysis, it is assumed that enough excess combustion air is supplied to ensure 3 mole percent oxygen in the flue gas.⁷

8.1.1.2 Thermal Incinerator Design Categories. For the purpose of costing, thermal incinerators are assigned to one of five broad design categories depending upon the presence of halogenated compounds in the reactor process vent stream and the heat content of the vent stream. For each category, the thermal incinerator design employed for a particular reactor vent stream depends upon the vent stream heat content, the flowrate, and the presence or absence of halogenated compounds. The basic fuel use requirements associated with each category are given in Table 8-1. For vent stream flowrates less than 14.2 scm/min, the heating value is calculated after dilution air is added to the stream to attain a minimum flowrate of 14.2 scm/min. The design incinerator inlet vent stream flowrates and the ratios used to predict flue gas flowrates for each design category are given in Table 8-2. These design flowrates are important in calculating equipment sizes and fuel costs. The design vent stream flowrates in Table 8-2 correspond to the maximum equipment sizes for each design category and they are used to determine the number of incinerators for proper combustion. The volume increase indicated by the flue gas to vent stream flow ratios is due to the addition of air and natural gas to the vent stream flowing into the incinerator.

Categories A1 and A2. All reactor process vent streams that contain halogenated compounds are included in design Categories A1 and A2. Categories A1 and A2 do not differ in control system design but only in supplementary fuel requirements. Category A1 includes all streams with heat contents less than or equal to 3.5 MJ/scm (95 Btu/scf); Category A2 includes

TABLE 8-1. INCINERATOR GENERAL DESIGN CRITERIA^{1,16}

Item	Criteria
Emission control efficiency	98 percent destruction of VOC.
Minimum incinerator volume ^a	1.01 m ³ (35.7 ft ³)
Incinerator temperature	
- nonhalogenated vent stream incineration	870°C - 980°C (1,600°F - 1,800°F)
- halogenated vent stream incineration ^b	1,100°C (2,000°F)
Furnace residence times	
- nonhalogenated vent stream incineration	0.75 sec
- halogenated vent stream incineration ^b	1.00 sec
Primary fuel requirement determined according to heating value of vent stream	Fuel required to maintain incinerator temperature with 3 mole percent excess air in flue gas
Supplemental fuel requirement. Required for flame stability calculated according to design category:	
Design Category ^c :	
A1	Add 0.33 MJ/scm of process vent stream flow (9 Btu/scf)
A2	Add 10 percent of process vent stream heat content value
B,C	Add 0.33 MJ/scm of process vent stream flow (9 Btu/scf)
D	Add 10 percent of process vent stream heat content value
E	Add 10 percent of diluted process vent stream heat content value
Recuperative heat exchanger	
Design Category ^c :	
A1, A2, D, E	None
B	Offgas and combustion air preheated. 70 percent heat recovery.
C	Combustion air preheated. 34 percent heat recovery.
Waste heat boiler	Applicable when the process vent stream flowrate is equal to or greater than 19.8 scm/min (700 scfm) and the vent stream contains corrosive compounds
Design Categories A1, A2	
Quench/Scrubber system	Used when corrosive compounds are present
- type	Packed tower
- packing height	11.0 m (36.0 ft)
- liquid/gas ratio	1337 l/m ³ (10 gal/ft ³)
- gas velocity	0.9 m/s (3.0 ft/s)
- scrubber gas temperature	100°C (212°F)
- quench and scrubber water	Varies according to flue gas flowrate

TABLE 8-1 (CONCLUDED). FOOTNOTES

^aIf calculated incinerator combustion chamber volume is less than 1.01 m^3 (35.7 ft^3), natural gas and air are added to maintain the design combustion temperature and residence time for a 1.01 m^3 (35.7 ft^3) incinerator volume.

^bNeeded to ensure complete combustion.

^cDesign categories are based on the following vent stream characteristics:

(HV = heating value of reactor process vent stream megajoules/standard cubic meter at 20°C and 1 atm, MJ/scm)

A1 halogenated, $\text{HV} \leq 3.5 \text{ MJ/scm}$

A2 halogenated, $\text{HV} > 3.5 \text{ MJ/scm}$

B nonhalogenated, $\text{HV} \leq 0.48 \text{ MJ/scm}$

C nonhalogenated, $0.48 \text{ MJ/scm} < \text{HV} \leq 1.9 \text{ MJ/scm}$

D nonhalogenated, $1.9 \text{ MJ/scm} < \text{HV} \leq 3.6 \text{ MJ/scm}$

E nonhalogenated, $\text{HV} > 3.6 \text{ MJ/scm}$

^dCategory E streams are diluted prior to incineration so that combustion temperatures would not exceed 980°C ($1,800^\circ\text{F}$). For determining the supplemental fuel requirement, the resultant net heating value after dilution is assumed to be 3.4 MJ/scm (92 Btu/scf).

TABLE 8-2. DESIGN CATEGORY BOUNDARY VALUE FOR REACTOR PROCESS
VENT STREAM FLOWRATES AND RATIO OF FLUE GAS
FLOWRATE TO OFFGAS FLOWRATE^a

Category	Maximum Design Vent Stream Flowrate per Incinerator (at Incinerator Inlet) ^b		Ratio of Incinerator Flue Gas Flow to Reactor Process Design Vent Stream Flow ^c
	(10 ³ scm/min)	(10 ³ scfm)	
A1 ^d	0.74	(26.1)	2.9
A2 ^d	0.74	(26.1)	2.9
B	1.42	(50.1)	1.9
C	1.42	(50.1)	2.3
D	1.25	(44.1)	2.5
E	1.25	(44.1)	2.5

^aReferences 1,2.

^bDesign flowrate = vent stream flowrate x 1.05.

^cBoth at standard temperature (20°C or 68°F) and pressure (1 atm or 14.7 psia).

^dReactor process vent contains halogenated compounds.

NOTE: 35.314 scfm $\equiv$ 1 scm/min

streams with heat contents greater than 3.5 MJ/scm (95 Btu/scf). Since the heat contents of Category A1 streams are lower, more supplementary fuel is required to maintain the proper incinerator temperature. Due to the greater difficulty of achieving complete combustion of vent streams containing halogenated VOC, an incineration temperature of 1,100°C (2,000°F) and a 1-second residence time were chosen to ensure that all halogenated streams will be controlled to a 98-weight-percent reduction efficiency or a 20 ppmv offgas concentration. Combustion temperatures exceeding 870°C (1,600°F) limit the use of recuperative heat exchangers due to limitations of materials of construction and due to the risk of precombustion in the exchangers. Therefore, recuperative heat exchangers are not used within these design categories. However, a waste heat boiler can be used effectively with flue gas temperatures up to 1,650°C (3,000°F).¹² A waste heat boiler with steam generation resulting in 60 percent heat recovery is included in the design criteria for these categories.¹³ The amount of heat recovery is limited by a minimum temperature of the outlet flue gas exiting the waste heat boiler (about 260°C (500°F)). Below this temperature, condensation of corrosive combustion products could occur.¹⁴ The design criteria for Categories A1 and A2 also include a quench/scrubber system for the removal of corrosive hydrogen halides formed in the incinerator. The resulting solution from the quench/scrubber is neutralized with caustic soda.

As mentioned previously, waste heat boilers are not available for streams with flowrates less than 19.8 scm/min (700 scfm). Where waste heat boilers are not used, an increase in the flow rate of quench water is required to cool the hotter flue gas, and a larger quench/scrubber chamber is needed to accommodate the larger volumes of steam and flue gas. For streams with flowrates below 19.8 scm/min, where no waste heat boiler is used, scrubber capital costs increase by about \$60,000 (1979 dollars) and the quench water flowrate increases from 0.063 l/scm/min (0.47 gal/1,000 scfm) of vent gas to a value of 1.1 l/scm/min (8.0 gal/1,000 scfm) of vent gas.

Category B. Design Category B incinerators are used for reactor process vent streams that do not contain halogenated VOC's and that have a heat content equal to or less than 0.48 MJ/scm (13 Btu/scf). This heat content corresponds to 25 percent of a typical VOC LEL in air.¹⁵ Streams with heat contents less than or equal to 25 percent of the LEL can be preheated without violating insurance requirements.¹⁵ For Category B, recuperative heat exchange resulting in 70 percent heat recovery is included in the design criteria. In this heating value range, the amount of heat recovery that can be obtained is limited by a ceiling of about 550-600°C (1,000-1,100°F) on the combustion air preheat temperature due to burner design considerations.¹⁶

Category C. Because of insurance requirements, reactor process vent streams with heat values greater than 0.48 MJ/scm (13 Btu/scf) and less than or equal to 1.9 MJ/scm (52.0 Btu/scf) may not be preheated.¹⁷ This heat value range corresponds to a range of 25-100 percent of the LEL in air for a typical organic vapor. Category C incinerators are used for all reactor

process vent streams within this heat content range that do not include halogenated VOC's. Because the majority of reactor process vent streams contain little or no oxygen, vent streams in this heat content range need not be diluted.¹⁸ While the vent stream is not preheated, the incinerator design criteria for Category C do include preheating the combustion air via recuperative heat exchange with the flue gas, resulting in 34 percent heat recovery.¹⁹

Category D. This design category applies to incinerators used to combust reactor process vent streams with heat contents greater than 1.9 MJ/scm (52.0 Btu/scf) and less than or equal to 3.6 MJ/scm (98.0 Btu/scf). Vent streams in this range are not preheated and require only a small amount of auxiliary fuel for flame stability. Because little fuel is needed, the use of recuperative heat recovery would not save much energy and thus is not economical to apply. The combustion temperature, which usually exceeds 870°C (1,600°F) and can be as high as 980°C (1,800°F), is dependent upon the heat content of the vent stream. A design temperature at the upper end of the possible range is used (980°C (1,800°F)) to avoid underestimating chamber costs.

Category E. Design Category E includes incinerators for reactor vent streams with heat contents above 3.6 MJ/scm (98.0 Btu/scf). Vent streams in Category E need not be preheated and require only a small amount of auxiliary fuel for flame stability. The vent stream composition again determines the combustion temperature and it is estimated combustion will occur at temperatures of approximately 980°C (1,800°F). High heating value reactor process vent streams in Category E are diluted to 3.6 MJ/scm (98 Btu/scf) and no heat recovery is employed. The dilution to 3.6 MJ/scm is required to ensure that the incineration temperature does not exceed 98°C. Excessive incineration temperatures may shorten the life of the combustion chamber. The supplemental fuel requirement is based upon the stream heating value after dilution.

8.1.1.3 Incinerator Auxiliary Equipment. Auxiliary equipment needed for a thermal incinerator control system includes ducting, pipe racks, a stack, and a fan for moving the vent stream from the source to the control device. A combustion air fan is also needed but the cost of this fan is included in the combustion chamber cost discussed in Section 8.2. In estimating the length of ducting required, it is expected that incinerators will be located as close to the process unit as possible, but far enough away to provide safety. Both the National Fire Protection Association and the Oil Insurance Association (now the Industrial Risk Insurers) concur that for petrochemical plants, a minimum safe distance of 200 feet should be used to separate a "high hazard" process unit and an enclosed combustion source.²⁰ Therefore, the incinerator design criteria include 61 m (200 feet) of ducting between the thermal incinerator and the edge of a process unit. An additional 30 m (100 feet) of ducting is added to route the vent stream from within the process unit to the edge of the process unit. Therefore, for the purposes of calculating costs, a total of 91 m (300 feet) of ducting is included.

In order to support the ducting, the costs of a pipe rack have been included in the cost estimates. The pipe rack is designed to support only the duct and pipe associated with a single reactor process unit. The size of the pipe rack included in the cost estimates is large enough to handle the ducting associated with the largest vent stream anticipated from a reactor process unit. The pipe rack consists of individual "T" shaped frames that are 16 feet tall to allow for passage of vehicular traffic. It is estimated that 13 A-36 structural steel pipe racks, each spaced about 20 feet apart, would be required to support the 91 m (300 feet) of ducting.¹¹

Fans are designed according to the combustion gas flowrate (i.e., vent stream, natural gas and air) and pressure drop across the incinerator system. Fans are designed to overcome pressure drops ranging from 6 to 22 inches of water which are the pressure drops for these incinerator systems.¹⁰ The overall pressure drop varies with the equipment used (e.g., an incinerator/boiler/scrubber system has a 22-inch pressure drop while an incinerator alone has a 6-inch pressure drop). Therefore, the power rating of the fan would vary depending on the incinerator system used.

8.1.2 Flare Design

8.1.2.1 General Design Criteria. The flare design consists of an elevated, guy-supported, steam-assisted, smokeless flare. Published correlations relating vent stream flowrate, heat content, and composition, to the flare height and tip diameter are used in the flare design.²⁰ The general design criteria used in developing these correlations are discussed below and are presented in Table 8-3. Additional equipment such as ducting, flare services, pipe racks, and a vent stream mover are also discussed in this section.

Flare height and tip diameter are the basic design parameters used to determine the installed capital cost of a flare. The tip diameter selected is a function of the combined vent stream and supplemental fuel flowrates, the combined gas temperature, mean molecular weight, and the gas exit velocity assumed at the flare tip. Supplemental fuel requirements and tip velocity values are shown in Table 8-3. Determination of flare height is based on worker safety requirements. The flare height is selected so the maximum ground level heat intensity from both the flare and sunlight does not exceed 440 Btu/hr-ft².²¹ Since solar radiation has an approximate value on a sunny day of 300 Btu/hr-ft², this corresponds to a heat intensity due to the flare alone of 140 Btu/hr-ft². The smallest flare commercially available is 30 feet high and 2 inches in diameter.²² For vent streams requiring smaller flare systems, a flare of this minimum size is included in the design criteria. Also included in the flare design criteria are the components of a liquid seal and gas seal. The gas seal prevents combustion of the flare gas within the flare stack. The water seal prevents entrainment of droplets carried into the flare combustion zone that could cause safety problems and that could reduce the flare VOC destruction efficiency.

TABLE 8-3. FLARE GENERAL DESIGN CRITERIA²⁰

Item	Criteria
Emission control efficiency	98 percent destruction
General flare design	Elevated, guy supported, steam assisted smokeless flare
- minimum flare tip diameter (D)	5.1 cm (2.0 inch)
- minimum flare height	9.0 m (30 ft)
- maximum ground level flare heat intensity	440 W/m ² (140 Btu/hr ft ²)
- flare tip velocity	V = 14.6 m/s (48 ft/s)
- flame emissivity	0.13
- number of pilots	1 for $D^a \leq 20$ 2 for $20 < D \leq 61$ 3 for $61 < D \leq 107$
- pilot gas requirement	2.36 scm/hr (80 scf/hr) of natural gas per pilot
- steam requirement	0.4 kg steam/kg vent gas
- purge gas requirement	Natural gas added to maintain a minimum flare tip velocity of 0.01 m/s (0.04 ft/s)
Supplemental fuel requirement	Natural gas required to maintain vent stream HV of 11.2 MJ/scm (300 Btu/scf)

^aD is the flare tip diameter in centimeters.

In designing a flare, first, flare tip diameter (D) and flare height (H) are calculated from empirical design equations^{23,24} using vent stream flowrate, VOC content, and heat content. The natural gas required for pilots and purge, and the mass flowrate of steam required are also calculated. Pilot gas consumption is a function of the number of pilots which, in turn is a function of the tip diameter as shown in Table 8-3. Based on the tip diameter, the number of pilots is selected and the pilot gas flowrate is calculated assuming a gas flow of 2.26 scm/hr (80 scf/hr) per pilot. The purge gas requirement is a function of the calculated flared gas velocity compared to the minimum allowable gas velocity at the tip. If the flared gas velocity is sufficient, no purge gas is required. A flare tip exit velocity of 14.6 m/s (48 ft/s) is used for design purposes. Based on test data, an exit velocity of 18.2 m/s (60 ft/s) ensures a VOC destruction of 98 percent when the heating value of the combined stream is at least 11.2 MJ/scm (300 Btu/scf). The exit velocity of 14.6 m/s (48 ft/s) used in this analysis contains a margin of safety to accommodate most unexpected vent stream surges and still maintain a 98 percent destruction efficiency. The steam requirement is the flow of steam needed to maintain a steam to flare gas ratio of 0.4 kg steam/kg vent gas.²⁵ The steam requirement is the estimated amount of steam needed to ensure smokeless flaring. Most reactor vent streams would actually require less than the specified 0.4 kg steam per kg of vent gas.

8.1.2.2 Flare Auxiliary Equipment. Auxiliary equipment needed for a flare system includes pipe or duct; flare services such as steam, air, and natural gas lines; pipe racks; and a vent stream mover. The design criteria include 120 m (400 feet) of ducting between the reactor process unit and the flare. Both the National Fire Protection Association and the Oil Insurance Association recommend a minimum safe distance of 91 m (300 feet) between the edge of a "high hazard" process unit and an open flame combustion device.^{26,27} An additional 30 m (100 feet) of duct is allowed to route the vent stream from within a process unit to the edge of a process unit. Therefore, 120 m (400 feet) of ducting have been included in the design criteria for flares.

Either pipe or duct is used to transport the reactor process vent stream to the flare base. For streams with flowrates less than 11.3 scm/min (400 scfm), a pipe is included in the flare design criteria. The pipe can have one of four possible diameters (i.e., 1, 2, 4, and 6 inches) depending upon the vent stream flowrate. Diameters are based on a maximum vent stream linear velocity of 610 m/min (2,000 ft/min). A 6-inch diameter pipeline has a maximum vent stream flowrate of 11.3 scm/min. For flow rates greater than 11.3 scm/min, duct is used because it is more economical than pipe for diameters over 6 inches. Since flares are not used to combust vent streams that contain halogenated compounds, all pipe, duct, and fittings are constructed with schedule 40 carbon steel.

Flare services include the natural gas, steam, and instrument air lines needed to provide these utilities at the flare base. The design criteria include 120 m (400 feet) of pipe for the natural gas, air, and steam lines.

The size of these lines are 2-inch diameters for gas and steam lines and a $\frac{1}{2}$ -inch diameter for the air line. These lines would be mounted on the pipe rack discussed later in this section.

The vent stream mover system included in the flare design criteria and costing procedures is different from the vent stream mover used for incinerators. When flares are used on nonhalogenated vent streams, the system pressure drop is about 21 inches of water whereas if an incinerator were used the pressure drop would be about 6 to 10 inches. Because of the difference in pressure drop, different types of vent stream movers are required for the two control systems.

The vent stream movers used to transport the vent stream from the reactor process unit to the flare were selected based upon a total system pressure drop and the economics of application. Based on a representative value of vent stream flowrate (3.4 scm/min, or 121 scfm), determined from all of the vent stream flowrate data contained in the reactor processes emission data profile (EDP), system pressure drop calculations were performed on the pipe or duct system, gas seal, water seal, flare stack, and tip.³¹ At the representative value of flowrate, the pipe or duct (including fittings) pressure drop is estimated to be 4.8 inches of water.³⁰ The pressure drop estimated for the gas and water seals as well as the flare stack and tip is approximately 16 inches of water. Therefore, the total system pressure drop is approximately 21 inches of water. Mover systems were selected to overcome this pressure drop.

Three types of gas movers are considered for use with either pipe or duct. The vent stream movers considered are: (1) a compressor, (2) a turbo-blower, and (3) a fan. For vent stream flowrates less than 1.2 scm/min (44 scfm), a compressor was used. Fans and turbo-blowers were not used because they cannot overcome the flare system pressure drop at these flowrates.²⁹ For vent stream flowrates between 1.2 and 244 scm/min (44 scfm to 8,600 scfm), a turbo-blower is more economical than a compressor or fan.²⁹ Either a pipe or duct is used with a turbo-blower depending on the flowrates as discussed above. A fan is included in the design criteria for streams with flowrates greater than 244 scm/min (8,600 scfm) because it is more economical than the other two mover devices for vent streams in this flowrate range. Only a duct is used in conjunction with the fan.

In order to support the 120 m (400 feet) of vent stream pipe or duct and flare services lines, a pipe rack is included in the design. The pipe rack is similar to that used for incinerators and consists of 18 "T"-shaped structures placed about 20 feet apart.²⁸ These structures are constructed of A-36 structural steel and are 16 feet tall to allow for the passage of vehicles. The pipe rack is sized to support the vent stream pipe and flare services pipes (natural gas, instrument air, and steam lines) associated with a single reactor process unit.³²

8.2 CAPITAL COSTS

The capital cost for each combustion control system includes the purchase and installation of all equipment, pipe or duct, vent stream movers, flare services, and pipe support necessary to route a vent stream from a reactor process unit to the control device. Equations used to estimate installed capital costs of incinerators and flares were generated by using a linear regression analysis of cost curves presented in an EPA report.^{33,34} Pipe or duct and mover costs are a summation of many individual component costs (i.e., ducts, fittings, valves, fans). Total installed capital cost equations used to determine the installed costs of pipe or duct, movers, flare services, and pipe support were based on design and cost information in Richardson.³⁵ Capital and installation costs for the turbo-blowers and fans were provided by a vendor.³⁶

The capital cost bases for incinerators, flares, pipe or duct, vent stream movers, flare services, and pipe racks are discussed in the following sections. All capital costs and cost equations are adjusted to third quarter 1982 dollars using Chemical Engineering plant cost indices for fabricated equipment.^{37,38,39}

8.2.1 Thermal Incinerators

Capital cost equations for thermal incinerator systems are based on cost curves.^{40,41} Individual cost equations for the incinerator combustion chamber, recuperative heat exchanger, and quench/scrubber are based on a linear regression analysis of these cost curves.

The incinerator cost equations provide a relationship between equipment cost and combustion chamber volume for three incinerator temperatures. The high temperature equation ($1,100^{\circ}\text{C}(2,000^{\circ}\text{F})$) is used when the reactor process vent stream contains halogenated components, the moderate temperature equation ($980^{\circ}\text{C}(1,800^{\circ}\text{F})$) is used for streams with relatively high heating values and the low temperature equation ($870^{\circ}\text{C}(1,600^{\circ}\text{F})$) is used when corrosive components are absent and the vent stream heating value is less than 1.9 MJ/scm (52 Btu/scf). In addition to the cost of the combustion chamber itself, the cost equations also account for the cost of fans, ducts, stack, and recuperative heat exchanger. An installation factor of 4.0 is applied to the combustion chamber capital cost equation to account for such installation cost factors as foundation, insulation, erection, instruments, painting, electrical, fire protection, engineering, freight and taxes.⁴² When a recuperative heat exchanger is included in the capital cost equations (see Section 8.1.1.2 for applicability) an installation factor of 2.6 is used to estimate installation cost of the heat exchanger.⁴³ The installation components considered are the same as those identified for the combustion chamber with the exception of fire protection.

Halogenated (corrosive) vent streams require the use of a quench/scrubber after the incinerator to remove the corrosive products of combustion. The capital cost of this system is determined as a function of the total incinerator exit gas flowrate. The cost equation is based on a linear

regression analysis of cost curves.⁴⁴ The total installed capital cost of the incinerator system is the summation of the combustion chamber, heat exchanger, and quench/scrubber costs and auxiliaries.

The capital costs for purchase and installation of ducting, a fan, and pipe racks are also included in the thermal incinerator costing procedure. As discussed in Section 8.1.1, the costs of 91 m (300 feet) of ducting and a fan are included in the costs of the control system.⁵⁷ The costs of a pipe rack to support the ducting are also included in the cost of the control system.

8.2.2 Flares

The total installed capital cost of a flare system is the sum of the costs of the flare itself, auxiliaries, and the pipe or duct and mover system. The capital cost of the flare itself is based on an EPA report that contains vendor supplied information. The EPA report provided data on the capital cost of a flare as a function of flare height and tip diameter for systems designed to burn propylene.⁴⁵ The vendor data provided information on capital costs for different flare height and tip diameters for flares combusting eight different VOC-containing streams. An installation factor of 2.1 was applied (see Table 8-4)⁶⁶, and a cost equation was developed from a linear regression analysis of both costing sources.²⁰ This equation yields the total installed capital cost of a flare as a function of height and tip diameter.

Other flare system costs include the capital costs for purchase and installation of the vent stream pipe or duct, pipe racks, flare services, and a vent stream mover. As discussed in Section 8.1.2, 120 m (400 feet) of pipe or duct supported by pipe racks are needed for the flare system. Flare services such as natural gas and steam line extensions are also provided. The purchase costs for these items are included in the flare costing procedures.⁴⁶

For the flare services, three separate conveyance pipes are needed. It is estimated that 2-inch diameter lines, each 400 feet in length, will be needed for steam and natural gas. The costs of Schedule 40, type A-53 grade B seamless carbon steel pipe are used in the cost estimation. In addition to the pipe costs, the costs of four 90° long radius ells, two globe valves, and four valve flanges are included. Costs are also included for a 1-inch thickness of fibrous glass pipe covering with fire retardant foil and a white kraft jacket to prevent significant amounts of steam condensation in the 2-inch diameter steam line. An additional 400 feet of pipe, 0.5 inches in diameter, is needed to provide instrument air. The costs of Schedule 40, type 304L, welded stainless steel pipe are included in the cost estimation. It is important that the instrument air line be clean and in particular be free of any particles of rust. Piping generally lies in the field prior to use in the process plant use. Therefore, stainless steel pipe was costed because it is resistant to atmospheric oxidation.⁴⁷⁻⁴⁹ Finally, the costs of pipe hangers for all three pipe lines are included in the capital costing

TABLE 8-4. FLARE INSTALLATION FACTORS⁶⁶

<u>Purchased Equipment</u>	
Primary and Auxiliary ^a	1.0
Instruments and controls	0.10
Taxes	0.03
Freight	0.05
Subtotal	1.18
<u>Installation</u>	
Foundations and supports	0.12
Handling and erection	0.40
Electrical	0.01
Piping	0.02
Insulation	0.01
Painting	0.01
Subtotal	0.57
<u>Indirect Costs</u>	
Engineering and supervision	0.10
Construction and field	0.10
Construction fee	0.10
Startup	.01
Performance test	.01
Contingencies	0.03
Subtotal	0.35
TOTAL	2.1

^aPrimary and auxiliary represent the cost of the following components: flare stack, flare tip, pilots, ignition panel, knockout drum, fluidic seal, and necessary piping at the flare.

procedure. The pipe rack costed is described in Section 8.1.2.2.⁵⁰ The total installed capital costs for flare services and the pipe rack are \$13,300 (1982 dollars) and \$12,000 (1982 dollars), respectively.

The total installed capital costs for the pipe mover systems, in 1982 dollars, ranges from \$4,300 for the 1-inch pipe/compressor system to \$18,900 for the 6-inch pipe/turbo-blower system. The total capital cost installation factor is approximately equal to 1.3 for all of the pipe or duct and mover systems.

For reactor process vent streams with flowrates larger than 11.3 scm/min (400 scfm), a duct/turbo-blower or duct/fan system is used to transport the vent stream to the flare base. At a flowrate of 424 scm/min (15,000 scfm), the total installed ducting cost is estimated to be \$33,000 (1982 dollars). The total installed capital cost for turbo-blowers ranges from \$4,400 (1982 dollars) for a vent stream flowrate of 1.2 scm/min (44 scfm) to \$11,000 (1982 dollars) for a flowrate of 244 scm/min (8,600 scfm) (1982 dollars). Total installed capital costs for fans range from \$7,500 (1982 dollars) at 244 scm/min (8,600 scfm) to \$20,000 (1982 dollars) at 679 scm/min (24,000 scfm).

8.3 ANNUAL COSTS

The annual costs of control for thermal incinerator and flare systems are presented in this section. The basis for calculating the annual costs for both systems are the same with a few exceptions.

The annualized costs include direct operating and maintenance costs, and annualized capital charges. The assumptions used to determine annualized costs are presented in Table 8-5, and are given in third quarter 1982 dollars. Direct operating and maintenance costs include operating, supervisory and maintenance labor, replacement parts, utility use, fuel consumption, and caustic use.⁵¹ Utility requirements include electricity (for compressors, turbo-blowers, and fans), steam for flare operation, and make-up water for quench system operation. Supplemental natural gas is required to increase the heating value of vent streams, to maintain pilot flames, and to purge flare systems. Caustic is required to neutralize acidic scrubber water. Direct operating, supervisory, and maintenance labor costs are determined from the design criteria developed for each control system and the annual cost factors presented in Table 8-5.

Capital charges include annualized equipment costs and indirect costs for overhead, taxes, insurance, administration and capital recovery. Annualized equipment costs and capital recovery are based on a 10-year life for incinerators and a 15-year life for flares.⁷⁰ Incinerators have a shorter life expectancy because combustion occurs within the incinerator chamber and corrosive vent streams are combusted at high temperatures. Under the design criteria, flares are not used to combust corrosive vent streams. Also, for flares, combustion occurs outside of the device. Therefore, flares have a longer life expectancy. A capital recovery is based on a 10 percent capital charge taken over the 10 or 15-year life span of the equipment. The assumptions used for capital charges are shown in Table 8-5.

TABLE 8-5. BASES FOR ANNUALIZED CONTROL SYSTEM COSTS

Direct Operating Cost Factors	
Hours of operation (hrs/yr) ^a	6,745
Total Labor^b	
(a) Operating labor ^c (1982 \$/hr)	12.05
(b) Supervisory labor	15% of operating labor
(c) Maintenance labor	3% of total installed costs
(d) Overhead	80% of a + b + c
Operating Labor (manhours)^b	
Incinerator	1,200
Incinerator with heat exchanger	2,133
Incinerator with scrubber	2,400
Flare	630
Pipeline/compressor or duct/fan "mover" system	0
Utilities and Reagents (1982 \$)	
Electricity ^e (\$/1,000 kWh)	51.20
Natural gas ^e (\$/10 ⁶ Btu, net heating value)	5.76
Quench and scrubbing water (\$/1,000 gal)	0.292
Steam (\$/1,000 lb) ^g	5.18
Caustic (\$/1,000 lb) ^f	57.89
Maintenance Materials	3% of total installed costs
Capital Charges	
Equipment life^h (years)	
Flares	15
Thermal Incinerator	10
Interest rate (percent)	10
Capital Recovery Factor^j (percent of total installed cost)	
Flares	13.14
Thermal Incinerator	16.27
Taxes, Insurance, Administration (percent of total installed cost)	4

^aReference 52.^bReference 56.^cReference 54.^dReference 53.^eReference 67.^fReference 76.^gReference 75.^hReference 56.ⁱBefore tax interest rate shown.^jCapital recovery factor = $\frac{1(1+i)^n}{(1+i)^n - 1} = 0.1627$ (thermal incinerators)

n = equipment life (10 yrs for incinerators; 15 yrs for flare)

i = interest rate (0.1)

To account for reduced production levels and downtime an annual capacity utilization factor of 77 percent is used.⁵² This translates into an annual operating level of 6,745 hrs/yr. Each of the operating cost parameters are reviewed below.

8.3.1 Labor

A summary of the labor cost basis is presented in Table 8-5. Labor costs are estimated by considering four categories of labor charges. These categories are (1) operating labor, (2) supervisory labor, (3) maintenance labor, and (4) overhead costs. The cost of operating labor was determined by referring to information provided by the U.S. Bureau of Labor Statistics.⁵⁴ This information indicates that the basic labor rate for an industrial organic chemical worker is \$12.05/hour, based on third quarter 1982 dollars. Supervisory labor is estimated to be 15 percent of the operating labor cost. Maintenance labor has been estimated to be equal to 3 percent of the total installed capital costs of the control system. Finally, overhead charges are estimated to be 80 percent of the sum of operating, supervisory, and maintenance labor costs. The sum of all four of these cost categories are collectively referred to as the total labor cost. These costs are representative of the SOCFI and are consistent with the labor costs found in other references.⁵⁵⁻⁵⁷

The operating labor requirements vary for the different design categories due to the specific system designs. Thermal incinerator categories A1 and A2 (halogenated streams) require 2,400 man-hours annually to operate the incinerator, waste heat boiler, and associated scrubber. Categories B and C (nonhalogenated, low heat content streams) require 2,133 man-hours per year since a scrubber is not part of the system design. Categories D and E (nonhalogenated, high heat content streams) require the least amount of labor (1,200 man-hours/yr) since no heat recovery equipment or scrubber is part of the system. The flare is a much simpler control device and requires an estimated 630 man-hours of operating labor per year. This includes the labor costs for operating flare services and all auxiliary equipment.⁵⁴

8.3.2 Utilities

The incinerator utilities considered in the annual cost estimates include natural gas and electricity. For incinerators where heat exchange is included in the design, natural gas costs are reduced. The cost estimates for incinerators used to control halogenated streams include a credit for heat recovery by means of a waste heat boiler. The amount of credit is based on the amount of energy recovered and the costs of natural gas. For Category A systems, the utility requirements also include scrubber water, quench makeup water, and caustic (as 50 percent solution). The caustic requirements are based on an assumed 1.2 percent chloride by volume in the flue gas to be treated. The cost associated with disposal of sodium salt from the neutralized scrubbing water (Categories A1 and A2) are not included in the annualized costs. These disposal costs would vary from facility to facility but are not expected to be a significant percentage of the total annualized costs.⁵⁸

Flare utilities considered in the annual cost estimates include natural gas (for supplemental fuel, purge gas, and pilot gas requirements), electricity (for operation of compressors, turbo-blowers, and fans), and steam for smokeless flare operation.

8.3.3 Fuel Requirements for Incinerators

Natural gas use curves and tables developed from detailed heat and material balances in an EPA report were used to determine fuel requirements for incinerators.⁵⁹⁻⁶² Reactor process vent streams belonging to Categories D and E have a higher heat content and require only a small amount of fuel for flame stability. The fuel requirement for these streams was assumed to be equivalent to 0.18 MJ of natural gas heat per standard cubic meter of vent gas independent of the vent stream heat content. This fuel requirement was chosen because it is equivalent to that calculated according to the Category C fuel use equation for vent streams with a heat content of 1.9 MJ/scm (which is the cutoff heat content distinguishing Categories C and D).

For the halogenated streams in Categories A1 and A2, heat and mass balance calculations for the designated combustion temperature of 1,100°C are not given in the report mentioned above. Therefore, the fuel requirements were interpolated from the curves for 980°C and 1,200°C. A fuel use equation was fit to this interpolated curve. This equation indicated that halogenated process vent streams in Category A2 with heat contents greater than 3.5 MJ/scm (95 Btu/scf) require primarily auxiliary fuel for flame stability. At this heat content, according to the fuel use equation, the amount of fuel required per standard cubic meter of vent gas is equivalent to 10 percent of the vent stream heat content.⁶³

Several assumptions are built into the fuel use equations. The most important is the assumption of no oxygen in the reactor process vent stream. This leads to combustion air requirements and a total incinerator inlet flow that will ensure complete combustion and prevent pyrolysis. It also increases fuel costs.

The design criteria of a maximum heat exchange efficiency of 70 percent may be too low for some facilities. A thermal incinerator system employing recuperative heat recovery could achieve a primary heat exchange efficiency as high as 85 to 95 percent.⁶⁴ Therefore, facilities able to employ such technology would have lower fuel requirements than are predicted by these gas use assumptions.

8.3.4 Fuel Requirements for Flares

Flares used to control reactor process vent streams with heat contents less than 11.3 MJ/scm (300 Btu/scf) require supplemental fuel. Natural gas is added in order to ensure a 98-percent destruction efficiency in the combustion of nonhalogenated vent streams. Natural gas is also required for purge gas and pilot gas requirements.

8.3.5 Natural Gas Price

The unit price (\$/10⁶Btu) of natural gas was determined by considering regional variations in natural gas prices and the long term affects of gas deregulation and other factors which could affect gas prices. Natural gas prices vary not only with time but also with location. To take this into account, EPA developed "best estimates" of 1990 natural gas prices in each of the ten Federal Regions based upon the gross heating value of the gas.⁶⁵ These prices were then weighted according to the estimated percentage of the SOCMIs located within each region. For each Region, the local natural gas price was multiplied by the Region's SOCMIs production weighting factor. These products were summed across all Regions to provide an overall natural gas price (at the gross heating value).

The SOCMIs production weighting factor for each region was calculated as the fraction of chemical production in a region divided by the estimated total production of SOCMIs chemicals in all 10 Federal Regions. The total chemical production and the chemical production in each region were determined from 1982 production data in Chapter 9. The total production capacity of each chemical for which there were available data (i.e., total capacity data shown in Table 9-1 and predominant plant locations shown in Table 9-8) were assigned to one of the 10 Federal Regions. The production capacities of all chemicals assigned to a region were summed to result in estimates of chemical production in each region.

Finally, the price was adjusted to the net heating value of the gas. Previous price estimates were based on the gross heating value. The gross heating value includes the energy recovered in condensing water vapor formed during combustion. This does not occur during incineration or flaring; therefore, the net heating value more accurately reflects the energy available.

Applying the price weighting method discussed above, the price of natural gas for reactor processes was estimated to be \$5.20/10⁶ Btu (gross heating value) or \$5.76/10⁶ Btu (net heating value)^{67,68}

8.3.6 Other Annual Costs

The costs for taxes, administration, and insurance are included in the estimate of annual costs. These three items collectively are estimated to be 4 percent of the total installed capital cost.⁶⁹

8.4 COMPARISON OF CONTROL SYSTEM COSTS

This section presents and discusses the capital costs, annualized costs, average cost effectiveness, and natural gas costs for the application of incinerators or flares to representative process vent streams. These costs are determined by applying the costing methodology, developed in the previous sections, to individual reactor process vent streams contained in the EDP.

For a specific combustion control system, capital and annualized costs vary with varying process vent stream flowrate and heat content. Therefore, five reactor process vent streams are used as examples to show how the costs of control vary for vent streams with a wide range of vent stream characteristics. These example cases are selected from the EDP, and represent the ranges of vent stream characteristics found in the EDP. Stream characteristics for the five example cases are as follows:

- Case 1 - Low flowrate, high heat content;
- Case 2 - Low flowrate, low heat content;
- Case 3 - High flowrate, high heat content;
- Case 4 - High flowrate, low heat content; and
- Case 5 - Medium flowrate and medium heat content.

Table 8-6 presents the capital costs, annualized costs, average cost effectiveness, natural gas cost, and vent stream characteristics for the five cases selected. All process vent stream characteristics used are based on data in the EDP. It should be noted that vent streams free of corrosive (halogenated) compounds are used so that both incinerators and flares are applicable to each stream.

Table 8-6 shows that average cost effectiveness for each control system varies with the reactor process vent stream characteristics. The lowest cost-effectiveness value shown occurs for the process vent stream (Case 3) with the highest vent stream energy flow (i.e., (flowrate) x (heat content), in MJ/min). The cost effectiveness for Case 3 ranges from \$53.8/Mg (\$48.8/ton) for incinerators to \$14.8/Mg (\$13.4/ton) for flares. In general, the low cost effectiveness values for high energy content vent streams are a result of the large mass of VOC available to support combustion and, subsequently, the low supplemental fuel costs. Also, relatively large VOC emission reductions occur for these streams, which greatly decreases cost effectiveness.

Table 8-6 also shows that the highest cost effectiveness occurs for vent streams with low energy flow (Case 2). This occurs even though this type of stream generally has low annualized costs. For Case 2, cost effectiveness ranges from \$150,000/Mg (\$137,000/ton) for flares to \$622,000/Mg (\$565,000/ton) for incinerators. As discussed in the following sections, application of controls to these low heat content streams results in moderately low costs but very low emissions reductions. A relatively small amount of VOC is controlled because of the low VOC content and/or low flowrates associated with these vent streams.

A comparison of capital costs is not discussed here because to do so without including the cost impacts for energy consumption would be misleading. For example, flares have the lower capital costs for all cases considered but have the lower annualized costs for only four of these example cases. This is a direct result of the energy costs associated with the fuel (natural gas) required for stable flare operation. Because of the effect of

TABLE 8-6. COST COMPARISONS FOR CONTROL OF EXAMPLE REACTOR PROCESS VENT STREAMS

Item	Case 1		Case 2		Case 3		Case 4		Case 5	
	Low Flowrate	High Heat Content	Low Flowrate	Low Heat Content	High Flowrate	High Heat Content	High Flowrate	Low Heat Content	Medium Flowrate	Medium Heat Content
Annualized Cost (1982 \$/yr)										
Flare	35,900		45,100		106,000		1,370,000		43,300	
Incinerator	225,300		186,500		386,000		312,000		180,500	
Capital Cost (1982 \$)										
Flare	65,200		65,200		127,000		148,000		76,900	
Incinerator	405,000		386,000		842,000		449,000		405,000	
Cost Effectiveness (\$/Hq. (\$/ton))										
Flare	605		150,000		14,80		5,060		2,190	
	(550)		(137,000)		(13.40)		(4,600)		(2,000)	
Incinerator	3,800		622,000		53.80		1,160		9,120	
	(3,450)		(565,000)		(48.80)		(1,050)		(8,280)	
Supplemental Natural Gas Cost										
(1982 \$/yr)										
Flare	2,810		11,900		5,620		1,210,000		2,810	
Incinerator	55,200		22,000		105,000		128,000		10,420	
Reactor Process Vent Stream Characteristics										
Flowrate scm/m (scfm)	0.26		0.25		20.6		34.0		2.0	
	(9.2)		(8.7)		(729)		(1,200)		(70)	
Heat content MJ/scm (Btu/scf)	27.9		0.15		45.9		0.55		12.0	
	(747)		(4.0)		(1,233)		(15)		(323)	
VOC flowrate Kg/hr (lb/hr)	8.91		0.045		1,086		40.6		3.0	
	(19.8)		(0.1)		(2,394)		(90)		(6.6)	

energy consumption on annualized costs, comparison of control system costs are presented on an annualized basis only.

Figure 8-1 illustrates the total annualized control costs for the five selected cases. The figure shows that flares are generally less expensive than incinerators. Specifically, flares are less expensive when applied to vent streams with low flowrates (Cases 1 and 2) and streams with high to medium heat contents (Cases 3 and 5). Incinerators have lower annualized costs when applied to vent streams with high flowrates and low heat contents (Case 4). High flowrate/low heat content streams require the most supplemental natural gas. Since the maximum heat content that may be used in the incinerators considered in this costing analysis is about 100 Btu/scf, as opposed to 300 Btu/scf for flares, much less gas is used for incinerators. This explains why the annualized costs for incinerators are lower than the annualized costs for flares when fuel requirements are high (as in Case 4).

The following is a case-by-case comparison and discussion of the annualized control system costs. Those cases that have similar cost trends are grouped together.

Cases 1 and 2. Both cases are characterized by vent streams with low flowrates. Figure 8-1 shows that for both cases the application of flares yields lower annualized costs than the application of incinerators. The relatively low annualized costs for flares is attributed to minimum flowrates of supplemental fuel required as a result of the low overall flowrates for these vent streams.

As shown in Figure 8-1, the incinerator system has the higher annualized cost for Cases 1 and 2. In general, the cost difference is due to the relatively high equipment costs for incinerators compared to flares. For both of these low flowrate cases, the minimum size incinerator of 14.2 scm/min (500 scfm) inlet flowrate is applied. As described in Section 8.1.1, additional dilution air is required to generate sufficient flue gas for maintaining the design residence time of this minimum size incinerator when a vent stream smaller than 14.2 scm/min is combusted. The dilution air also results in additional supplementary fuel being required. As shown in Table 8-6, the supplemental fuel costs required for incinerator operation under Cases 1 and 2 range from \$22,000 to \$55,200/yr.

Case 3. Case 3 represents vent streams with a high energy content and high flowrate. Because of the high energy content, these streams require little or no supplemental fuel for combustion with a flare. For flares, the contribution of natural gas cost to the annualized cost is about 5 percent. Annual steam costs are the single largest contributor to Case 3 flare annualized costs. For thermal incinerators, Case 3 is a Category E stream that is diluted with air to reduce the heat content to a value of 3.65 MJ/scm (98 Btu/scf). Prior to combustion, the vent stream has a diluted flowrate that is increased in volume to 280 scm/min (9,170 scfm). Although auxiliary fuel is required only for flame stability, natural gas costs are large

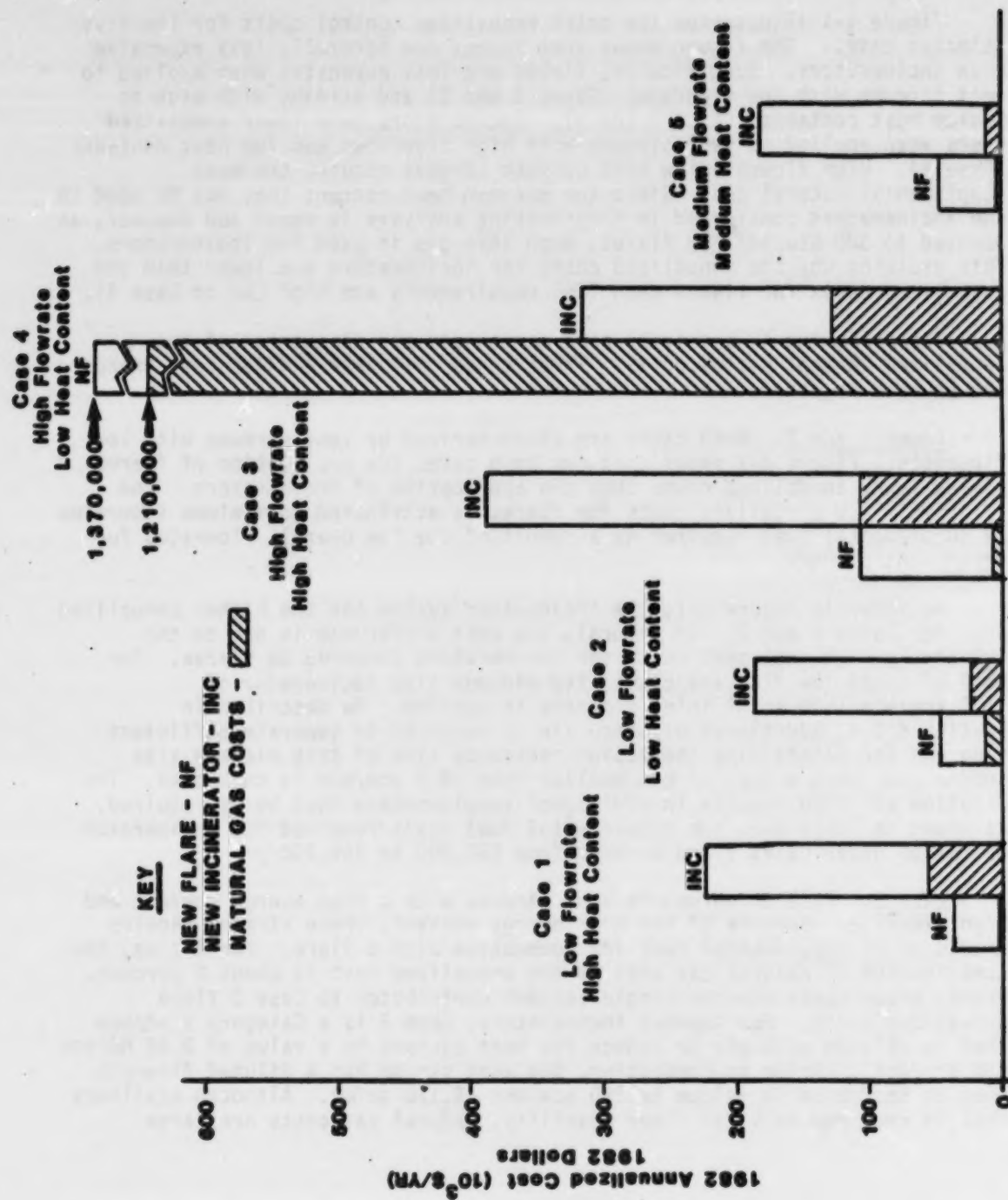


Figure 8-1. Annualized control cost comparisons for example reactor process vent streams.

because they are a function of the increased volume of the diluted flow. Natural gas costs constitute about 30 percent of Case 3 annualized costs. The annualized capital charges associated with the cost of the incinerator also contributes a significant portion of the total annualized costs.

Case 4. Case 4 results in the highest annualized costs for flares as compared to the other four cases. In addition, flares are much more expensive than incinerators because of the supplementary fuel necessary for flare operation. Figure 8-1 shows that the high annualized cost of flares is a direct result of the high energy cost. A large amount of supplemental fuel is required for both flares and incinerators because the vent stream flowrate is high, and its corresponding heat content is low. Table 8-6 shows that the natural gas costs for a flare are \$1,210,000/yr, representing about 90 percent of the total annualized cost of control, as compared to gas costs of \$128,000 for thermal incinerators, representing 40 percent of the annualized cost.

It is the difference in fuel requirements that drives the annualized cost of flares much higher than the cost of incinerators. The flare cost procedures require that enough fuel be added to this vent stream to reach a minimum heat content of 11.2 MJ/scm (300 Btu/scf) while the incinerator equations add enough fuel to maintain a heat content of approximately 3.7 MJ/scm (100 Btu/scf).

Case 5. Incineration is more expensive than flaring in Case 5 because of the relatively large capital cost contribution to the total annualized costs. For incinerators the capital cost is \$405,000, whereas for flares the capital cost is \$76,900. The vent stream characteristics of Case 5 for thermal incinerators represent a Category E stream. However, because the flowrate is less than 14.2 scm/min (500 scfm) the heat content decreases to 1.7 MJ/scm (45 Btu/scf) after air is added to attain the minimum flowrate of 14.2 scm/min (see Section 8.1.1.1). The adjusted heat content shifts the vent stream from Category E to Category C. The natural gas costs represents less than 6 percent of the total annualized cost. Incinerator capital costs are relatively large because a larger combustion volume is required to incinerate the increased volume of the diluted vent stream.

8.5 NATIONAL COST IMPACTS

Section 8.5.1 describes the method used to calculate the costs of VOC control associated with each of the regulatory alternatives described in Chapter 6, and Section 8.5.2 summarizes the national cost impacts of each regulatory alternative.

8.5.1 Determination of National Cost Impacts

As discussed in Section 6.3.2.2, a total of 56 new, modified, and reconstructed reactor process units with vent streams that are not combusted at baseline are projected to come on-line during the first 5 years of the standards' applicability. In order to calculate national costs of control, the costs of control were first calculated for each of these 56 process units. For projected process units with vent streams that are nonhalogenated,

the cost of controlling VOC with either an incinerator or a flare were calculated. The less expensive of the two control systems, in terms of annualized cost, was chosen as the basis for the cost impacts analysis. For process units with halogenated vent streams, only the costs of applying an incinerator for VOC control were calculated. The costs of applying flares were not calculated because the use of flares on halogenated vent streams would result in uncontrolled hydrogen chloride emissions. This problem can be avoided where incinerators are used by adding a scrubber after the incinerator.

The costs of applying flares or incinerators to the 56 process units were calculated based on predicted vent stream characteristics such as flowrate, VOC content, and halogen content. The vent stream characteristics for each of the 56 process units were developed as described in Section 6.3.2.3. The incinerator and flare design criteria and costing procedures described in Sections 8.1 through 8.3 were used to calculate the annual costs of control for each of these process unit vent streams.

Once the annual costs of control were calculated, TRE values were calculated for each of the 56 process units. As discussed in Section 6.3.3, TRE values were calculated for each process unit by dividing the annualized cost of combustion control for that process unit by the annual emissions reduction achievable. (The achievable emissions reductions at each projected process unit were based on 77 percent capacity utilization and 98-weight-percent VOC reduction by the control device, as described in Sections 7.2.1 and 8.3).

Regulatory alternatives are defined by specific TRE cutoff values presented in Section 6.3.3. Under the baseline regulatory alternative, it is assumed that new, modified, and reconstructed reactor process units are controlled at the same level as currently operating units producing the same chemical. Under baseline (in the absence of an NSPS) combustion controls would not be applied to any of the 56 projected new, modified, and reconstructed process units. Under the other regulatory alternatives, Alternatives II - IX on Table 8-7, controls are applied to those uncombusted vent streams with TRE values that are less than a specified cutoff value. For example, an alternative may consist of control of all new, modified, and reconstructed process units with TRE values less than \$1,000/Mg of VOC controlled.

For a given regulatory alternative, the national costs were determined by summing the costs of applying combustion control to vent streams from each projected new, modified, or reconstructed process unit which has a TRE value less than or equal to the TRE cutoff value.

8.5.2 Results of the Cost Analysis

The national cost impacts of each regulatory alternative are shown in Table 8-7. Costs are expressed in third quarter 1982 dollars. The national annualized costs represent the cost of control of reactor process VOC

TABLE 8-7. SUMMARY OF COST IMPACTS AT SELECTED REGULATORY ALTERNATIVES^a

Alternative Number	TRE Cutoff (\$/Mg)	Number of Process Units Controlled	National Emissions (Mg/yr)	Percent of "Controllable" Emissions Reduced ^c	National Annualized Cost (1,000 \$/yr)	National Average TRE (\$/Mg) S.G. ^d
I	0 Baseline	0	3,000	0	0	-
II	1,200	4	2,700	13	150	500
III	2,500	7	900	90	3,700	1,700
IV	5,500	9	800	91	3,900	1,800
V	20,000	21	690	97	4,700	2,100
VI	50,000	33	620	100.	6,700	2,900
VII	200,000	42	610	100.	7,400	3,200
VIII	500,000	46	610	100.	8,200	3,500
IX	>500,000	56	610	100.	9,300	4,000

^aCosts of control in the fifth year after NSPS implementation exclude enforcement costs.

^bCosts are expressed in third quarter 1982 dollars.

^cControllable emissions are the 2,400 Mg/yr that would be controlled if all 56 units were controlled at 90-percent destruction efficiency (i.e., at the most stringent possible alternative, Alternative IX).

^dAt each TRE Cutoff: Nationwide Average TRE (\$/Mg) = (National Annualized Cost)/(Baseline National Emissions [3,000 Mg/yr] - National Emissions at given TRE cutoff [Mg/yr]).

emissions attributable to the NSPS in the fifth year after proposal of the NSPS. These values do not include the costs of reporting, recordkeeping, or enforcement of the standard. The national annualized costs range from zero dollars at baseline to \$9.3 million under the most stringent regulatory alternative (control of all 56 projected new, modified, and reconstructed reactor process units).

The calculation of national VOC emissions and percent of emissions controlled under each regulatory alternative, shown in Table 8-7, are discussed in Chapter 7.

The national average TRE under a given regulatory alternative is the national annualized cost of control divided by the national VOC emissions reduction due to the given regulatory alternative. The national average TRE ranges from \$0/Mg at baseline to \$4,000/Mg under the most stringent regulatory alternative.

8.6 CONTROL COST ACCUMULATION FOR REACTOR PROCESSES CHEMICALS

8.6.1 Introduction

In 1977, Congress passed the Clean Air Act Amendments, authorizing EPA to propose new source performance and hazardous air pollutant standards for industries that pollute the Nation's air. Since 1977, EPA has initiated action on ten such standards that would directly affect the chemicals that would be affected by the reactor processes NSPS. Three of these standards have been promulgated, four have been formally proposed, and three have been dropped from consideration. The background information documents (BIDs) prepared in support of these ten standards examine their economic impacts, but, with few exceptions, they consider only the costs associated with a single standard--not the cumulative costs of all applicable standards. This section aggregates the individual costs of these standards to find their accumulated economic impact on chemicals that may be affected by the reactor processes NSPS.

8.6.2 Background--Industry, Standards, and Methodology

8.6.2.1 Reactor Processes Industry. As defined here, the reactor processes industry consists of facilities involved in the production of any of 173 chemicals having a minimum national production level of 45.4 Gg/yr, including both basic and intermediate chemicals used in the production of a wide range of end products. According to the projections described in Section 9.1.6, the consumption of only 110 of these chemicals will grow in the near term. Of these 110 chemicals, only 26 will have vent stream characteristics that will cause them to be impacted directly by the reactor processes NSPS under the most stringent regulatory alternative. Table 8-8 lists these 26 chemicals, the estimated number and size of the facilities needed to meet projected capacity requirements, the cost of controlling emissions at each of these facilities, and the total control cost of all the

TABLE 8-8. PROJECTED FACILITY SIZE AND COST
FOR 26 REACTOR PROCESS CHEMICALS

Chemical	Number of projected facilities	Size of projected facilities, Gg	Control cost for each facility, \$ 1982	Total cost, ^a \$ 1982
Adipic acid	2	236	396,356	792,712
Benzyl chloride	1	36	386,904	386,904
Butyl acrylate	1	35	43,548	43,548
n-Butyl acetate	1	23	37,036	37,036
t-Butyl alcohol	8	5	38,838	310,704
t-Butyl hydroperoxide	1	11	67,840	67,840
Chlorobenzene	1	68	411,492	411,492
p-Chloronitrobenzene	1	18	381,820	381,820
Cyanuric chloride	1	18	378,900	378,900
Diacetone alcohol	3	7	35,780	107,340
Diethylbenzene	1	18	36,392	36,392
2,4-(and 2,6)- dinitrotoluene	1	17	105,019	105,019
2,4-Dinitrotoluene	1	80	269,986	269,986
Ethyl acetate	4	15	41,256	165,024
Ethyl acrylate	2	40	99,742	199,484
Ethylbenzene	8	318	56,332	450,656
Ethylene oxide	3	204	1,174,592	3,523,776
Isopropyl alcohol	1	206	169,783	169,783
Methyl methacrylate	4	95	59,394	237,576
Nitrobenzene	1	153	39,256	39,256
1-Phenylethyl hydroperoxide	1	18	214,784	214,784
Phenylpropane	1	18	36,392	36,392
Propylene oxide	2	322	172,896	345,792
Trimethylene	1	18	61,270	61,270
Vinyl acetate	4	193	35,776	143,104
Vinyl trichloride	1	45	390,885	390,885

^aTotal cost is projected to the dollar based on the algorithms presented earlier in Chapter 8. These are the best estimates of possible costs to control emissions from each chemical. Thus, although these estimates have not been rounded, the values given do not necessarily imply the precision usually suggested by nonrounded values.

facilities projected for each chemical. The number of facilities required for each chemical is calculated using a specific facility size and the amount of additional capacity required to meet projected growth in the consumption of each chemical in the 5-year period following proposal of the reactor process standard in the Federal Register. Control costs are scaled according to the size of the specific facility selected for each chemical.

The 26 chemicals listed in Table 8-8 represent the projected set of potentially impacted chemicals in the 5-year period following proposal of the reactor processes standard in the Federal Register. The costs for all 26 chemicals at the number of process units projected are summed to yield the national costs of this standard under the most stringent regulatory alternative. Under different regulatory alternatives, some or all of the 26 chemicals will not require control because their cost-effectiveness (TRE) value exceeds the associated cutoff. This cumulative impacts analysis will examine the impacts of the reactor processes NSPS on the 26 chemicals as well as the impact of previously proposed and promulgated standards. In doing so, this analysis will yield worst-case impacts on SOCMIs, since it is likely that fewer chemicals ultimately will be impacted under the regulatory alternatives finally selected for the reactor processes NSPS.

8.6.2.2 Previous Standards. Proposed and promulgated air pollutant emissions standards that affect these 26 chemicals are:

- NESHAP: Benzene Fugitive Emissions. Promulgated June 6, 1984, 48 FR 12387.
- NSPS: VOC Fugitive Emissions in Synthetic Organic Chemicals Manufacturing Industry. Promulgated October 18, 1983, 48 FR 48328.
- NSPS: VOC Fugitive Emissions in Petroleum Refining. Promulgated May 30, 1984, 48 FR 22598.*
- NSPS: VOC Emissions from Volatile Organic Liquid Storage Tanks. Proposed July 23, 1984, 49 FR 29698.
- NSPS: VOC Emissions from Distillation Process Vents in the SOCMi industry. Proposed December 30, 1983, 48 FR 57538.
- NSPS: VOC Emissions from Air Oxidation Process Vents in the SOCMi Industry. Proposed October 21, 1983, 48 FR 48932.

*Due to similar control technologies, the SOCMi Fugitive Emissions NSPS, and the Petroleum Refining Fugitive Emissions NSPS are treated jointly, and their costs are lumped together.

NSPS: VOC Emissions from Reactor Processes Vents in the
SOCMI Industry. Currently being proposed.

The first five standards require control technologies that, for the most part, are independent of the processes used to produce the 26 chemicals. However, the last two standards, those for air oxidation and the reactor processes, are production process specific--i.e., defined by the particular production process used to produce the chemicals. Thus, because some of the chemicals can be produced by either of the processes, some of the 26 chemicals are subject to regulation under either standard, depending on the process used to produce them.

Although proposing both standards ensures the control of VOC emissions during the production of the 26 chemicals irrespective of production process, it nevertheless complicates the process of estimating the cumulative impacts of all the standards affecting SOCMI.

Specifically, because each of the standards assumes that all future capacity will produce each chemical with only one process, the aggregation methodology must count the impacts of only one standard, not both, in estimating the cumulative impact. Otherwise, there is double counting of the actual control costs imposed, because each chemical will be subject only to the controls specified for the process used to produce it.

Therefore, to estimate the cumulative costs of all standards affecting the SOCMI industry, this analysis incorporates the costs associated with only one of the two process-specific standards. Although, theoretically, the costs of either standard would function equally well, those associated with the reactor process standard are used here because, as shown in Section 9.1.6, they were derived using more specific information on all the 26 subject chemicals.

8.6.2.3 Methodology. The basic methodology employed to generate the cumulative annualized control costs is summarized below:

- o All control costs are standardized to mid-1982 dollars.
- o Costs are annualized by a capital recovery factor and a 10 percent real interest rate.
- o All control costs are incremental and do not include the cost of pollution control equipment already in place.

Control costs are cumulated for all reactor process chemicals that have projected growth, have process vents, and are uncombusted at baseline.

For the NESHAP regulation, control costs derived from model plants are multiplied by the number of existing facilities affected.

- o Where future facilities are concerned, the fifth-year total annualized control costs for model facilities are used for accumulation. Fifth-year annualized costs refer to the control costs expected to be incurred by society in the fifth year after proposal of each standard in the Federal Register. The fifth year will vary among potential regulations because the dates of proposal in the Federal Register vary. This analysis standardizes fifth-year costs by assuming that the fifth year is 1990, the fifth year of the proposed reactor processes standard. This is accomplished by multiplying the estimated per-facility cost of each standard by the number of facilities projected to come on-line between 1985 and 1990 for the 26 chemicals (see Table 8-8).
- o Only the EPA Administrator's recommended regulatory alternative is considered when accumulating costs for the previously proposed and promulgated standards. If the most stringent regulatory alternative were considered, the cumulative cost estimates would reflect unreasonably extreme values for calculating the impacts on the 26 chemicals. By considering the potential impacts on all 26 reactor processes chemicals, EPA has already established an extreme set of chemicals to use for the analysis, but not an unreasonable one. However, by employing the worst possible costs of each regulation for the largest possible set of chemicals impacted under the reactor processes standard, a grossly overexaggerated impact on the 26 chemicals would occur. While it is important to analyze potential impacts under extreme conditions, it is impractical to make those conditions unrealistic.
- o The costs that are cumulated in this section are the direct costs of the various SOGMI standards. In Section 9.3.3, both direct and indirect costs are used to examine price impacts. The indirect costs are those that are rolled-through from one producer to another.

8.6.3 Data and Assumptions for Accumulating Costs

This section presents the specific data and assumptions used for each of the proposed and promulgated standards to estimate cumulative costs for the 26 reactor processes chemicals. The discussion for each standard includes information on sources of cost data and the per-facility costs associated with the relevant regulatory alternatives. Control costs for the benzene fugitives NESHAP are broken down into per-facility costs for existing facilities and per-facility costs for future facilities and then are aggregated in Table 8-9. Control costs for the other NSPS are simply per-facility costs for future facilities, except those for the reactor processes NSPS, which is costed on a chemical-specific basis. The control costs of each regulation are presented in Table 8-10 in the base-year dollars of the particular standard. Section 8.6.5 below presents the converted control costs of each regulation in the common base year, mid-1982 dollars. The costs in Table 8-10 are converted by a procedure described in Section 8.6.4.

TABLE 8-9. FACILITY-SPECIFIC COSTS OF THE BENZENE FUGITIVE EMISSIONS
NESHAP FOR BENZENE-CONSUMING REACTOR PROCESSES CHEMICALS
WITH PROJECTED CAPACITY ADDITIONS

Chemical	Existing facilities ^a	Cost per existing facility ^b (\$)	New facilities ^c	Cost per new facility ^b (\$)	Total cost (\$)
Chlorobenzene	3	8,700	1	18,200	44,300
Ethylbenzene	14	8,700	8	18,200	267,400
Nitrobenzene	6	8,700	1	18,200	70,400

^aReference 71.

^bCost to existing facilities will be \$8,700 based on the average of the model facilities for Regulatory Alternative III in the benzene fugitive emissions EIS. Cost to future facilities will be \$18,200 based on the average of the model facilities for Regulatory Alternative IV.

^cSee second column in Table 8-8.

TABLE 8-10. ANNUALIZED CONTROL COSTS IN FIFTH YEAR^a AFTER PROPOSAL FOR FOUR AIR QUALITY STANDARDS BASED ON FACILITY PROJECTIONS FOR 26 REACTOR PROCESSES CHEMICALS^b

Chemical	Number of projected facilities	Benzene fugitive NESHAP ^c (1979 \$)	VOC fugitive NSPS (1978 \$) ^d	VOL storage NSPS (1982 \$) ^e	Distillation NSPS (1978 \$)
Adipic acid	2		26,800	4,962	141,600
Benzyl chloride	1	--	13,400	2,481	70,800
Butyl acrylate	1	--	13,400	2,481	70,800
n-Butyl acetate	1	--	13,400	2,481	70,800
t-Butyl alcohol	8	--	107,200	19,848	566,400
t-Butyl hydroperoxide	1	--	13,400	2,481	70,800
Chlorobenzene	1	44,300	13,400	2,481	70,800
p-Chloronitrobenzene	1	--	13,400	2,481	70,800
Cyanuric chloride	1	--	13,400	2,481	70,800
Diacetone alcohol	3	--	40,200	7,443	212,400
Diethylbenzene	1	--	13,400	2,481	70,800
2,4-(and 2,6)-Dinitrotoluene	1	--	13,400	2,481	70,800
2,4-Dinitrotoluene	1	--	13,400	2,481	70,800
Ethyl acetate	4	--	53,600	9,924	283,200
Ethyl acrylate	2	--	26,800	4,962	141,600
Ethylbenzene	8	267,400	107,200	19,848	556,400
Ethylene oxide	3	--	40,200	7,443	212,400
Isopropyl alcohol	1	--	13,400	2,481	70,800
Methyl methacrylate	4	--	53,600	9,924	283,200

See footnotes at end of table.

(continued)

TABLE 8-10 (continued)

Chemical	Number of projected facilities	Benzene fugitive NESHAP (1979 \$)	VOC fugitive NSPS (1978 \$) ^d	VOL storage NSPS (1982 \$) ^e	Distillation NSPS (1978 \$)
Nitrobenzene	1	70,400	13,400	2,481	70,800
1-Phenylethyl hydroperoxide	1	--	13,400	2,481	70,800
Phenylpropane	1	--	13,400	2,481	70,800
Propylene oxide	2	--	26,800	4,962	141,600
Trimethylene	1	--	13,400	2,481	70,800
Vinyl acetate	4	--	53,600	9,924	283,200
Vinyl trichloride	1	--	13,400	2,481	70,800

^aFifth-year costs are assigned for reactor processes control period 1985-1990. The cost per chemical for the other regulations are 1990 fifth-year costs in that their per-facility costs are multiplied by the number of facilities projected in the reactor processes analysis to come on-line in the 5-year period.

^bFacility projections for reactor processes chemicals assume that all capacity added to accommodate chemical growth is capacity to produce that chemical by reactor processes only. See Table 9-17.

^cSee Table 8-9.

^dCost per facility is \$13,400. Total cost equals 13,400 times the number of facilities in the first number column and represents the costs for both NSPS's.

^eCost per facility is \$2,481. Total cost equals 2,481 times the number of facilities in the first number column.

^fCost per facility is \$70,800. Total cost equals 70,800 times the number of facilities in the first number column.

8.6.3.1 Benzene Fugitive Emissions NESHAP. Cost data are from the draft Environmental Impact Statement (EIS) entitled "Benzene Fugitive Emissions--Background Information for Proposed Standards," November 1980 (EPA-450/3-80-032a).⁷⁰ Cost data in the EIS are in May 1979 dollars. The benzene NESHAP would affect only those chemicals in the list of 26 reactor processes chemicals that are benzene consumers. Table 8-9 presents the three chemicals that fall into this category, along with the cost to control current and future facilities.

EPA promulgated Regulatory Alternative III for existing sources (46 FR 1175). This alternative, which requires the installation of certain equipment and monthly monitoring for detection of leaks, is expected to reduce benzene fugitive emissions by about 70 percent. EPA promulgated Regulatory Alternative IV for new sources (46 FR 1177) and estimates an emissions reduction of about 80 percent for this alternative. The estimated cost per existing facility is \$8,700, which is the weighted average of the cost to three model facilities chosen by EPA for the analysis. The annualized cost of control for model facility A is \$7,400, and it is estimated that 62 percent of existing benzene-related production units are represented by model A. The annualized cost of control for model B is \$9,700, and this model is representative of an estimated 31 percent of existing production units. Model C's annual cost of control is \$15,200, and it represents 7 percent of existing units.

The estimated cost per facility for new facilities for Regulatory Alternative IV is \$18,200, which is also a weighted average of the same three model facilities. Model A is estimated to incur control costs of \$12,000; model B, \$25,700; and model C, \$39,000. The analysis assumes that new facilities will follow the same distribution as the current population.

Table 8-9 shows the number of plants currently producing each of the affected chemicals and the cost per facility of controlling those existing plants, \$8,700. The table also shows the number of reactor processes facilities that are projected to be built between 1985 and 1990 for the three chemicals. The per-facility cost of \$18,200 for new facilities is multiplied by this number and added to the total cost for existing facilities to derive the total cost of the benzene emissions standard on this subset of the 26 reactor processes chemicals. Table 8-10 presents these totals in the context of the costs for all the standards affecting the 26 reactor processes chemicals.

8.6.3.2 VOC Fugitive Emissions in SOCM and Petroleum Refining Fugitive Emissions NSPS. Cost data are from the draft EIS entitled "VOC Fugitive Emissions in Synthetic Organic Chemicals Manufacturing Industry--Background Information for Proposed Standards," November 1980 (EPA-450/3-80-033a).⁷² Cost data in the EIS are in fourth-quarter 1978 dollars and are assumed to represent the costs of control from both NSPS. The VOC fugitive emissions NSPS would affect all 26 reactor processes chemicals.

EPA promulgated Regulatory Alternative IV (46 FR 1136). The annualized cost of this alternative is \$13,400 per facility for installing equipment to control VOC emissions. The figure of \$13,400 is an average of three model facilities weighted by the percentage of current facilities that most resemble each model facility. The annualized cost of control for model facility A is \$7,900; for model facility B, \$13,300; and for model facility C, \$33,000. The VOC fugitive emissions EIS estimates that 52 percent of existing facilities are similar to model A, while 33 percent resemble B, and 15 percent resemble C. It is assumed that future facilities will resemble each model plant in the same proportions as current facilities.

To arrive at chemical-specific costs of control, the \$13,400 per-facility annualized control cost is multiplied by the number of new sources shown in Table 8-8. The total cost for each chemical for the control of its fugitive emissions of VOC is given in Table 8-10.

8.6.3.3 Volatile Organic Liquid Storage Tanks NSPS. Cost data are from the draft EIS entitled "VOC Emissions from Volatile Organic Liquid Storage Tanks--Background Information for Proposed Standards," June 1983 (EPA-450/3-81-003a).⁷³ Control costs are in 1982 dollars in the EIS. The Volatile Storage NSPS would affect all 26 chemicals.

EPA recommends Regulatory Alternative IV from the draft EIS. The total annualized cost of control for the entire industry is assumed to be \$1.68 million to be incurred by an estimated 677 expansion and replacement tanks. This figure comes from Tables 9-15 and 9-20 in the VOL storage draft EIS, which gives the total number of projected storage tanks to be built in the 5-year period after proposal and the percentage of this number that will require control technology. If total annualized cost to the industry is split equally among these 677 sources, a cost of \$2,481 per tank will be incurred.

To arrive at chemical-specific costs, the \$2,481 cost per tank is multiplied by the projected number of new sources for each of the 26 chemicals (see Table 8-10).

8.6.3.4 Distillation NSPS. Cost data are from the draft EIS entitled "Distillation Operations in Synthetic Organic Chemical Manufacturing--Background Information for Proposed Standards," December 1983 (EPA-450/3-83-005a).⁷⁴ Cost data in the EIS are in fourth-quarter 1978 dollars. The Distillation NSPS would affect all 26 chemicals.

Control costs per facility are calculated under two separate sets of control conditions. Worst-case conditions reflect extreme assumptions about the number of columns, the flow rate for the vent streams, the energy requirements and recovery during VOC combustion, and the number of incinerators, all of which cause the per-facility cost to be an overstated maximum value. Most-likely conditions reflect the control costs that are most likely to prevail at affected plants in the industry. These conditions

are based on a flare preference for VOC combustion, and a 98-percent VOC emissions reduction alternative. The control costs associated with these most likely conditions are used. The control cost per facility under these conditions is \$70,800.

To estimate chemical-specific annual fifth-year costs of control of distillation columns for the fifth year of the reactor processes standard, the annual cost of \$70,800 is multiplied by the number of facilities projected to come on-line in the 1985 to 1990 period for each of the 26 chemicals. The total annual cost in the fifth year for each chemical for the control of its distillation column is given in Table 8-10.

8.6.3.5 Reactor Processes NSPS. Cost data are obtained from the emissions data profile (EDP) in Section 3.3 and from the sizes of projected facilities in Section 9.1.6 of this document. Cost data are in 1982 dollars. The cost data in the EDP are scaled to the specific projected facility sizes for each chemical. Table 8-8 shows the cost for each projected facility, and these are the costs used in the cumulation procedure for this analysis. Section 8.2 presents a more detailed description of the cost methodology.

8.6.4 Cost Conversion

To present a standardized figure for total accumulated cost for the 26 reactor processes chemicals, all cost figures for the various regulations are converted by appropriate price indices to the 1982 dollars used in this reactor processes NSPS.

Costs for the benzene fugitive emissions NESHAP are presented in second-quarter 1979 dollars. The chemical equipment cost index for second quarter 1979 is 592.0 (1926 = 100); for mid-1982, the index is 763.2. Therefore, the costs in Table 8-9 for the three chemicals affected by the benzene NESHAP are multiplied by $763.2/592.0$ to update the costs to 1982 dollars.

Costs for the VOC fugitive emissions NSPS and for the distillation NSPS are presented in fourth-quarter 1978 dollars. The chemical equipment cost index for fourth quarter 1978 is 560.4 (1926 = 100). To update the costs associated with this regulation to mid-1982 dollars, a scalar of $763.2/560.4$ is multiplied by all costs in the respective totals column of these standards in Table 8-10.

Costs for the VOL storage tanks NSPS are presented in mid-1982 dollars, and therefore no conversion is necessary for these costs. As mentioned above, costs for the reactor processes NSPS are also presented in 1982 dollars and no conversion is necessary for them either.

8.6.5 Presentation of the Cumulative Impact of Seven Clean Air Act Standards on the SOCHI Industry

The costs in the totals column for the seven standards in Table 8-10 are multiplied by the appropriate indices to give the converted costs by chemical for each standard shown in Table 8-11. These standardized fifth-year annualized costs are then aggregated to get the total cost of the proposed and promulgated standards that affect each chemical potentially impacted by the reactor processes NSPS. The total cumulated costs for the 26 subject chemicals in Table 8-11 is 16.3 million dollars, and the cumulated cost for each chemical ranges from 88,000 to 3.9 million dollars. The impacts of these costs for each chemical are examined in detail in Section 9.4.

TABLE 8-11. ANNUALIZED CONTROL COSTS^a IN FIFTH YEAR^b AFTER PROPOSAL
FOR SEVEN AIR QUALITY STANDARDS BASED ON FACILITY PROJECTIONS
FOR 26 REACTOR PROCESSES CHEMICALS
(1982 \$)

Chemical	Annualized control costs					Total cumulated cost
	Benzene fugitive NESHAP ^c	VOC fugitive NSPS ^{d,e}	VOL storage NSPS	Distil- lation NSPS	Reactor processes NSPS ^f	
Adipic acid	--	36,502	4,962	192,860	792,712	1,027,036
Benzyl chloride	--	18,251	2,481	96,430	386,904	504,066
Butyl acrylate	--	18,251	2,481	96,430	43,548	160,710
n-Butyl acetate	--	18,251	2,481	96,430	37,036	154,198
t-Butyl alcohol	--	146,008	19,848	771,440	310,704	1,248,000
t-Butyl hydro- peroxide	--	18,251	2,481	0	67,840	88,572
Chlorobenzene	57,103	18,251	2,481	96,430	411,492	585,757
p-Chloro- nitrobenzene	--	18,251	2,481	96,430	381,820	498,982
Cyanuric chloride	--	18,251	2,481	96,430	378,900	496,062
Diacetone alcohol	--	54,753	7,443	289,290	107,340	458,826
Diethylbenzene	--	18,251	2,481	96,430	36,392	153,554
2,4-(and 2,6)- Dinitrotoluene	--	18,251	2,481	96,430	105,019	222,181
2,4-Dinitro- toluene	--	18,251	2,481	96,430	269,986	387,148
Ethyl acetate	--	73,004	9,924	385,720	165,024	633,672
Ethyl acrylate	--	36,502	4,962	192,860	199,484	433,808
Ethylbenzene	344,678	145,008	19,848	771,440	450,656	1,732,630
Ethylene oxide	--	54,753	7,443	289,290	3,523,776	3,875,262

See footnotes at end of table.

(continued)

TABLE 8-11 (continued)

Chemical	Annualized control costs					Total cumulated cost
	Benzene fugitive NESHAP ^c	VOC fugitive NSPS ^{d,e}	VOL storage NSPS	Distillation NSPS	Reactor processes NSPS ^f	
Isopropyl alcohol	--	18,251	2,481	96,430	169,783	286,945
Methyl methacrylate	--	73,004	9,924	385,720	237,576	706,224
Nitrobenzene	90,745	18,251	2,481	96,430	39,256	247,163
1-Phenylethyl hydroperoxide	--	18,251	2,481	96,430	214,784	331,946
Phenylpropane	--	18,251	2,481	96,430	36,392	153,554
Propylene oxide	--	36,502	4,962	192,860	345,792	580,116
Trimethylene	--	18,251	2,481	96,430	61,270	178,432
Vinyl acetate	--	73,004	9,924	385,720	143,104	611,752
Vinyl trichloride	--	18,251	2,481	96,430	390,885	508,047
Total						16,264,643

^aAll costs shown are in 1982 dollars. These costs are projected to the last dollar based on algorithms presented in the Draft EISs associated with each standard and because of converting the costs to 1982 dollars. These cost estimates are the best available but should not be taken literally as their numerical precision suggests they should.

^bFifth-year costs are assigned for reactor processes control period 1985-1990. The costs per chemical for the six other regulations are 1990 fifth-year costs in that their per-facility cost is multiplied by the number of facilities projected to come on-line in the 5-year period.

^cCost index to convert original costs for this standard from second quarter 1979 dollars to mid-1982 dollars is $763.2/592 = 1.289$.

^dCost index to convert original costs for this standard from fourth-quarter 1978 dollars to mid-1982 dollars is $763.2/560.4 = 1.362$.

^eThese costs represent both SOGMI Fugitives and Petroleum Refining Fugitives NSPS's.

^fThese costs of control are associated with production by reactor processes (which is mutually exclusive of production by air oxidation) and therefore represents the costs of both standards.

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CHAPTER 9 ECONOMIC ANALYSIS

9.1 INDUSTRY PROFILE

This profile of the Synthetic Organic Chemical Industry (SOCMI) contains a general description of the industry and detailed industry statistics and growth projections. Material is presented in six sections. The first section describes the SOCMI as a whole and defines the reactor processes segment of the industry. The next four sections describe supply and demand, market structure, prices, and market performance, respectively. The sixth section contains growth projections through 1990. Most data used in the profile are current through 1982.

9.1.1 Industry Overview

9.1.1.1 Definition of SOCMI. The chemicals of concern here largely fall into Standard Industry Classification (SIC) category 286, Industrial Organic Chemicals. SIC 286 is part of a broader classification, Chemicals and Allied Products, which also includes industrial inorganic chemicals, polymers, pharmaceuticals, agricultural chemicals, and other products. Where data for organic chemicals are unavailable for this profile, information for chemicals and allied products is often used. In other places, The Kline Guide to the Chemical Industry¹ is used. The Kline publication uses a definition of the chemical industry that excludes allied chemical products but includes petroleum refining, metal industries, and photographic equipment with industrial chemicals, polymers, and agricultural products. Data presented are generally for the area including the 50 States, the District of Columbia, and Puerto Rico.

Organic chemicals may be classified as basic, intermediate, or end-product. Basic chemicals are produced directly from petroleum, coal, natural gas, or living matter. These chemicals are used in the production of intermediate chemicals, which are subsequently used in the manufacture of a number of end-product chemicals.

SOCMI is a very complex industry, currently producing more than 7,000 different chemicals.² Organic chemicals are widely used in manufacturing and other industries, for example, as inputs in polymer production, pharmaceuticals, construction, and automotive products. The basic-to-intermediate-to-end-product classification has some limitations because of these disparate

uses: a number of chemicals may be used for some purposes as intermediate chemicals and for others as end-product chemicals. Also, since many chemicals can be produced by several processes, it is often possible to substitute one input for another as price changes dictate.

The interdependence of the chemicals and the variety of end uses to which they can be put makes SOCFI, like the chemicals industry as a whole, difficult to describe. This interdependence has influenced the structure of the industry, encouraging vertical integration among chemical firms. These firms have found it profitable to expand in the industry both forward from industries such as petroleum and agriculture and backward from industries such as pharmaceuticals and paint goods. Expansion of chemical companies to nonchemical areas is also common.

Total SOCFI production as reported by the U.S. International Trade Commission (USITC) for 1982 was 135,683 Gg, of which 67,920 Gg were sold for \$54,270 million.³

9.1.1.2 Description of the Reactor Processes Chemical Group. SOCFI is subdivided into sectors according to production process. Though the number of chemicals produced by SOCFI is large, as noted in Chapter 3, a small percentage of chemicals accounts for most of the industry's total production. These few chemicals are primarily produced by reactor, or conversion, processes, which alter the molecular structure of chemical compounds. Because these few chemicals so dominate industry output, the scope of the SOCFI standards development effort is designed to cover only these chemicals. Thus, this study considers only those reactor processes chemicals with a national production level of 45.4 Gg/yr or higher--173 synthetic organic chemicals.

Table 9-1 summarizes 1982 data for the 173 chemicals,⁴⁻¹⁰ including national production and capacity, imports and exports, and prices. In general, these data provide an overview of the chemicals and are used as bases for some of the industry growth projections presented in Section 9.1.6. Where specific data are unavailable, spaces in the table are left blank. Most sources for the data in Table 9-1 provide 1982 information, although some list only older data. These outdated data are included in the table but are updated in the subsequent projections analysis to be consistent with the other 1982 data.⁴⁻¹⁰ Where 1982 import and export data are not available, they are estimated from the most recent preceding year's data.⁴⁻⁵ Estimates are made assuming that 1982 imports and exports maintained the same percentage relationship to total consumption that they did in the year of the most recent available data. Average 1982 list prices are tabulated if available,⁴⁻⁵ or an average of four spot prices reported in the 1982 Chemical Marketing Reporter is used.⁵ For some chemicals, chemical-specific or end-use group average 1978 prices from the distillation operations background information document (BID) are used.¹¹ These prices are updated to 1982 prices using equipment cost indices.¹²

TABLE 9-1. PRODUCTION, FOREIGN TRADE, AND PRICES^a FOR 173 REACTOR PROCESSES
CHEMICALS, UNITED STATES, 1982

Chemical	End-use group ^d	Production, Gp/yr	Capacity, Gp/yr	Utilization, Average, %	Imports ^c		Exports ^c		Chemical price ^e \$/kg
					Gp/yr	Percentage of domestic production	Gp/yr	Percentage of domestic production	
Acetaldehyde	GM	181	454	40	0	0	0	0	75
Acetic acid	PF	1248	1905	66	0.5	0	52	4	58
Acetic anhydride	PF	499	690	71	9	2	9	2	90
Acetone	GM	797 ^f	1361	58	52	6	0	0	66
Acetone cyanohydrin	PF	495							30
Acetylene	PF	134	143	94					121
Acrylic acid	PF	128 ^g	354 ^h						55
Acrylonitrile	SE	926	1175	79	0	0	364	39	115
Adipic acid	PF	680	803	85	5	1	16	2	52
Adiponitrile	SE		1361 ^g						132
Alcohols, C-11 or lower (mixtures)	GM	51 ^f							60
Alcohols, C-12 and higher (mixtures)	GM	314							100
Alcohols, C-12 or higher (unmixed)	GM	82 ^f							45
Allyl chloride	GM		299						121
Aniline	GM		327 ^g						55
Anilines (mixed)	GM								126
Aniline	PF	261	581	45	0	0	0	0	57
Benzene	BC	3548	7761	45	447	13	121	3	84
Benzenesulfonic acid, mono-C ₁₀ 18-allyl derivatives, sodium salts	DS		236						46
Benzyl chloride	GA	54	82	61					21
Bisphenol A	PF	240	374	64	0	0	19	0	112
Bisvinyl	SE	828	2107	39					51 ^g
Bromotone	PF								104
Butadiene and butene fractions	SE	488 ^f	2144 ^f	23 ^f					47
Butanal	PL	455	717 ^f	64 ^f					
Butane	BC	780 ^f							77
1,4-Butanediol	GM	136 ^f	163	83 ^f					35
Butanes (mixed)	GM								29
2-Butoxyethanol	SO	1811	3014	60	15	1	220	12	172
Butyl acrylate	CO								73
n-Butyl acetate	CO	118 ^g							33
n-Butyl alcohol	GM	51	68	75	0	0	18	35	150
tert-Butyl alcohol	SO	314	535	59	3	9	39	12	106
sec-Butyl alcohol	GM		458 ^g						48
Butylbenzyl phthalate	GM	40 ^g	370						70
n-Butylene	PL	154 ^f	685 ^g	81 ^g	0	0			159
p-Butylene	BC		68 ^g						72
Butylenes (mixed)	PF	255 ^f	752 ^f	14 ^g					77
tert-Butyl hydroperoxide	PF								35
									99
									45
									66
									38
									17 ^g
									42
									19 ^g
									100
									45

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TABLE 9-1 (cont. inued)

Chemical	End-use group ^d	Production, Gg/yr	Capacity, Gg/yr	Utilization, Average, %	Imports ^c		Exports ^c		Chemical price \$/kg
					Gg/yr	Percentage of domestic production	Gg/yr	Percentage of domestic production	
2-Butyn-1,4-diol	GM		249 ^g						319
Butyric anhydride	GM	320	540	59					145
Caprolactam	PF	127	304	42	2	2	1	1	98
Carbon disulfide	PF								45
Carbon tetrachloride	GM	267	494	54	1	0	15	6	190
Chloroacetic acid	DS	58	64	91	16	29	0	0	86
Chlorobenzene	GA	106	227	47					37
Chloroform	MI	135	236	57	9	6	15	11	42
p-Chloronitrobenzene	OV		46 ^g						123
Citric acid	MI	136 ^h	163 ^h	84 ^h	5	3	19	13	56
Cumene	GA	1215	2006	58	70	6	10	1	84
Cumene hydroperoxide	PF		459 ^g						31
Cyanuric chloride	PF		73 ^g						68
Cyclohexane	PF	577	1322		63	1	52	9	174
Cyclohexanone, oxidized	GM		272 ^g						79
Cyclohexanol	GM		23 ^h						82
Cyclohexanone	GM	272	1089	25					181
Cyclohexanone oxime	GM								53
Cyclohexene	GM								24
Diacetone alcohol	GM		27						319
1,4-Dichlorobutene	SE		249 ^g						55
3,4-Dichloro-1-butene	SE	68 ^f							121
Diethanolamine	DS								137
Diethylbenzene	GA								62
Diethylene glycol	PF	175	292	60	0		18	10	132
Diisobutyl phthalate	PL	49							72
Dimethyldichlorosilane	PF								33 ^g
Dimethylterephthalate	PL	2828 ^f	1860						462
2,4-(and 2,6-) Dinitrotoluene	PF	229 ^f	386						210
2,4-Dinitrotoluene	PF	110	232	29	0	0	34	15	70
Dioctyl phthalate	GM	209 ^f							201
Dodecene	GM								91
Dodecylbenzene, linear	DS	118 ^f	465 ^{f,j}	49					112
Dodecylbenzene, non-linear	DS	113 ^f	465 ^{f,j}	49					51
Dodecylbenzenesulfonic acid	DS	281 ^g							101
Dodecylbenzenesulfonic acid, sodium salt	DS								46
Epichlorohydrin	GM	170	290	59	0	0	16	9	101
Ethanolamine	DS	106	295	61	0	0	64	35	101
Ethyl acetate	SO	72	122	59	0	0	44	60	106
Ethyl acrylate	CO	110 ^g							93
Ethyl alcohol	SO	463	824	56	35	8	89	19	181
Ethylbenzene	PL	1027	4714	63	0	0	24	1	111

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TABLE 9-1 (continued)

Chemical	End-use group ^a	Production, Gg/yr	Capacity, Gg/yr	Utilization, Average, %	Imports ^c		Exports ^c		Chemical price, \$/lb
					Gg/yr	Percentage of domestic production	Gg/yr	Percentage of domestic production	
Ethyl chloride	GM	154	302	51	0	0	12	8	53
Ethylene dibromide	BC	11195 ^f	17917	62	102	1	0	0	53
Ethylene dichloride	GM	77 ^f			15		0		38
Ethylene glycol	NI	4529	8101	56	72	2	340	0	31
Ethylene glycol monoethyl ether acetate	NI	1948	3014	65	15	1	220	11	73
Ethylene glycol monoethyl ether	SO	79							91
Ethylene glycol	SO								42 ^b
2-Ethylhexyl alcohol (2-Ethylhexyl) amine	GM	2210	3275	67					115
6-Ethyl-1,2,3,4-tetrahydro-9,10-anthracenedione	PL	145	227	64	29	20	19	13	52 ^b
Fluorocarbon 113	GM								70
Formaldehyde	PF	2128	4128 ^k	52	0	0	5	0	88
Freon 11	AP	66	465	63					20
Freon 12	AP	136	465 ^k	63					9
Freon 21	AP	95	465 ^k	63 ^f					141
Freon 22	AP	59 ^f	70 ^f	84 ^f					163
Glycerin	FA								74 ⁱ
Heptane	GM	50 ^f							157
Heptenes (mixed)	GM	16 ^f							71
Hexane	SE	476	975 ^g		0	0			253
Hexamethylene diamine	SE								114
Hexamethylene diamine adipate	PF		68 ^g	62 ^g					176
Hexamethylene tetramine	PF								80
Isobutane	BC	480 ^f							42
Isobutyl alcohol	SO	64 ^f	109						19
Isobutylene	PF	213	335	64					34
Isobutyraldehyde	PL	137 ^f	177 ^f	78					40
Isopentane	BC	5746 ^g							42
Isoprene	SE	230 ^f	280 ^f	82					92
Isopropyl alcohol	GM	594 ^f	1340	44	0	0	85	14	101
Kerosene	GM								82
Linear alcohols, ethoxylated (mixed)	PL	226 ^f							51
Linear alcohols, ethoxylated and sulfated, sodium salts (mixed)	DS	62 ^f							112
Maleic anhydride	PL	122	163	75	0.5	0	3	2	22
Mesityl oxide	SO		28 ^h						10
Methyl alcohol	GM	3295	5141	62	120	4	449	14	66

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TABLE 9-1 (cont. nued)

Chemical	End-use group	Production, Gg/yr	Capacity, Gg/yr	Utilization, %	Imports ^c		Exports ^c		Chemical price \$/kg
					Gg/yr	Percentage of domestic production	Gg/yr	Percentage of domestic production	
Methylamine	GM	102	157	65					115
ar-Methylbenzenediamine	PF								100
Methyl chloride	GM	135	311	43	0	0	8	6	44
Methyl chloroform	SO	268	433	62	0	0	32	12	77
Methylene chloride	SO	230	376	63	18	8	28	12	35
									53
Methyl ethyl ketone	SO	204 ^f	408	50	18	9	32	15	24
Methyl isobutyl ketone	SO	71	111	64 ^f	0	0	7	10	88
Methyl methacrylate	GM	386	585	66	1	0	45	12	108
1-Methyl-2-pyrrolidone	GA								49
Methyl-t-butyl ether (MTBE)	FA	771	1361	57					137
Naphthalene	BC	64 ^f	318 ^f	20 ^f					260
Nitrobenzene	PF	485	760 ^f	64 ^f					118
Nonyl alcohol	PL				0	0	0	0	40
Nonyl phenol	DS	64	173	37					18
Nonylphenol, ethoxylated	DS	92 ^d							40
Octene	PL								22
Oil-soluble petroleum sulfonate, calcium salt	DS	538 ^f							75
3-Pentenitrile	PF								34
Pentaerythritol	PF	45	84	54	5	10	7	15	84
Pentenes (mixed)	GM	74 ^f							112
Perchloroethylene	SO	265	460	58	17	4	20	43	52
Phenol	GA	969	1406	69	0.5	0	50	6	97
1-Phenylethyl hydroperoxide	PF								44
Phenylpropane	GA								108
Phosgene	GM	760	898	87					46
Phthalic anhydride	PL	320	617	52	0.5	0	5	2	79
Propanal	GM								36
Propane	BL	356d ^f							22
Propyl alcohol	SO	65	100	65	0	0	15	23	10
Propylene	BC	5575							92
Propylene glycol	PF	182	395	46 ^f	214	4	41	1	46
Propylene oxide	GM	816 ^f	1252 ^f	65 ^f	0.5	0	34	19	71
Sorbitol	GM	79	205	39	25 ^f	3	60 ^f	8	97
Styrene	PF	2699	4106	66	10	23	7	9	99
Terephthalic acid	PL	1944	3012	65	11	0	499	18	101
Tetraethyl lead/tetramethyl lead	FA	125 ^f	170 ^f	73					77
Tetrahydrofuran	SO				0	0	134	7	35
Tetra (methyl-ethyl) lead	FA	60 ^f							686
									275
									107
									364
									165

Footnotes on last page of table.

TABLE 9-1 (cont.ued)

Chemical	End-use group ^d	Production, Gg/yr	Capacity, Gg/yr	Utilization Average, %	Imports ^c		Exports ^c		Chemical price €/kg
					Gg/yr	Percentage of domestic production	Gg/yr	Percentage of domestic production	
Toluene	BC	479			58	12	9	2	269
Toluene-2,4-diamine	BC	93							185
Toluene 2,4- (and 2,6)-diisocyanate (80/20 mixture)	PF	261	318	82	1	0	77	30	205
Trichloroethylene	SO	81	154	53	6	8	15	19	68
Triethanolamine	DS	58							108
Triethylene glycol	GM	52	82	64	0	0	5	8	57
Tripropylene	MI		256						120
Vinyl acetate	CO	851	1089	78	3	0	317	37	37
Vinyl chloride, monomer	PF	2946	4256	68	23	1	418	14	71
Vinylidene chloride	PF	97	318						32
Vinyl trichloride	SO	92	326						40
Xylenes (mixed)	BC	2400	750	53	137	6	282	12	61
m-Xylene	PF				70	16	0	0	28
o-Xylene	PF	355	481	74	16	4	176	49	75
p-Xylene	PF	1449	2433	60	35	2	394	27	46

^aSources of price data include Knoxville Chemical Products, Chemical Marketing Reporter, U.S. International Trade Commission Statistics, The SRI Directory of Chemical Producers, and Toxic Substances Control Act Surveys.

^bData are for the year 1982 unless otherwise footnoted.

^cImport and export values for 1982 are taken from the sources above, if available. Otherwise 1982 imports and exports are estimated from the most recent preceding year for which they were recorded, by assuming that imports and exports remain a constant percentage of domestic consumption.

^dEnd-use abbreviations are

BC Basic Chemicals
 GA General Aromatics
 GM General Monaromatics
 SE Synthetic Elastomers
 PF Plastics and Fibers
 PL Plasticizers
 PE Pesticides
 DV Dyes
 SO Solvents
 DS Detergents and Surfactants
 FA Fuel Additives
 AP Aerosol Propellants and Refrigerants
 CO Coatings
 MI Miscellaneous

^ePrices are list prices from the sources in footnote a when available. Some are an average of four spot prices for the year 1982, from Chemical Marketing Reporter.

^fData are for 1981.

^gData are for 1977.

^hData are for 1980.

ⁱ1978 prices from the distillation operations B10, ¹¹ converted to 1982 dollars using equipment cost index for chemicals from Chemical Engineering.

^jCapacity includes both linear and nonlinear dodecylbenzene.

^kCapacity includes from 11, Freon 12, and Freon 22.

^l1978 end-use group average from distillation operation B10, ¹¹ converted to 1982 dollars using equipment cost index for chemicals from Chemical Engineering.

Note: Situations where production data exceed capacity data are adjusted in subsequent use of the data.

Total 1982 production of the 173 chemicals is approximately 86,041 Gg. This figure is based on a variety of sources, including assumed minimum production levels of 45 Gg/yr for those chemicals for which current chemical-specific data are unavailable. Among the highest volume chemicals are ethylene, ethylene dichloride, and propylene.

For 88 chemicals, sufficient data are available to calculate capacity utilization. In general, capacity utilization in 1982 was 45 to 75 percent. This was lower than in past years, due in part to the effects of the 1981 to 1983 recession. However, as the economy recovers, a steady increase in demand should increase capacity utilization by about 4 percentage points per year through the 80s from the average rate of 60 percent in 1982.¹³

About 70 chemicals are imported or exported in sufficient volume to show up in foreign trade statistics. In general, imports are less than 15 percent of domestic production of a particular chemical. Overall, exports represent a greater volume than imports but are generally less than 20 percent of domestic production.

Table 9-1 also gives 1982 prices for 144 of the chemicals. They range from \$0.20/kg to \$6.06/kg. The highest priced chemicals are tetraethyl lead and tetramethyl lead; most prices are between \$0.40 and \$2.00/kg.

9.1.2 Supply and Demand

The market conditions that determine the amount of production and consumption of chemical products at a given time--i.e., the supply and demand conditions of the industry--are discussed in this section.

9.1.2.1 Supply Conditions.

9.1.2.1.1 Product description. The 173 chemicals can be grouped into 14 end-use categories based on position in the manufacturing chain and ultimate use.¹⁴ These chemical end-use groupings are as follows:

- Basic chemicals
- Intermediates: general aromatics
- Intermediates: general nonaromatics
- Intermediates: synthetic elastomers
- Intermediates: plastics and fibers
- Intermediates: plasticizers
- Intermediates: pesticides
- Intermediates: dyes
- Solvents
- Detergents and surfactants
- Fuel additives
- Aerosol propellants and refrigerants
- Coatings
- Miscellaneous end-use chemicals.

The end-use group for each chemical is included in Table 9-1. It is important to note that these end-use groups are independent of the type of chemical reaction used in the production process shown in Section 3.5. This end-use grouping scheme is useful for identifying growth and other trends within the industry. The groups are referred to throughout this industry profile.

In general, basic and intermediate chemicals are commodities, which are chemicals produced in high volume at comparatively low prices. About 60 percent (by weight) of all organic chemicals produced in recent years are basic and intermediate compounds.¹⁵ The majority of these are basic or intermediate petrochemicals and solvents; the remainder are gum- and wood-product chemicals and fatty acids.¹⁵

In contrast to commodity chemicals, end-product chemicals are generally produced in smaller volume and sold at higher prices. These chemicals are used directly by consumers or by other industries and are more differentiated than are the basic and intermediate chemicals.

9.1.2.1.2 Factors of production. The primary inputs for the industrial chemicals sector, which includes both inorganic and organic chemicals, are other chemicals, as might be expected due to the chain of production of chemicals from basic to end-product chemicals.¹⁶ Other important inputs are energy, maintenance, transportation and storage services, petroleum, and miscellaneous products of petroleum and coal. Professional and business services also are significant production factors in the industry.¹⁶ Some of these inputs are discussed below.

Raw Materials. The organic chemical industry depends largely on petroleum and petroleum products for raw material as inputs. The partial deregulation of petroleum products and the Organization of Petroleum Exporting Countries (OPEC) cartel production quotas during the 1970s contributed to rising prices in the chemical industry. Table 9-2 shows a comparison between an average price index of five oil-based chemicals and an index of crude oil prices from 1970 to 1984.¹⁷⁻¹⁹ The percentage change in the chemicals index parallels the percentage change in the crude oil index in both direction and magnitude of change in each year since 1973. Table 9-3 shows a similar comparison of indexes between natural gas prices and an average price of five gas-based chemicals.^{17,18} Natural gas does not show the same direct price influence on gas-based chemicals that crude oil does on its chemicals. In fact, rarely does the percentage change in the two indexes shown in Table 9-3 move in the same direction in any given year. This is due apparently to the effects of long-term contracts for the use of natural gas as a feedstock for chemical production.

The chemical industry as a whole has comparatively low expenditures for raw materials. The Kline Guide reports that 56.8 percent of the value of chemical sales went toward raw materials, compared to 59.7 percent for all manufacturing. This indicates a relatively higher level of processing costs and value-added for the industry.²⁰ The ratio of expenditure for raw

TABLE 9-2. COMPARISON OF PRICE INDEXES BETWEEN CRUDE OIL AND THE
AVERAGE PRICE OF FIVE OIL-BASED CHEMICALS^a 1970-1984^{17 18 19}
(Base year = 1973)

Year	Five oil-based chemicals			Crude oil		
	Average price, \$/kg	Index	Percent change in index	Price, ^b \$/Barrel	Index	Percent change in index
1970	12.0	0.78	--	--	--	--
1973	15.3	1.0	28	4.13	1.00	--
1974	26.4	1.72	72	9.63	2.33	133
1975	27.6	1.80	5	10.93	2.65	14
1976	29.1	1.90	6	10.89	2.64	0
1977	29.9	1.95	3	11.96	2.90	10
1978	31.3	2.05	5	12.46	3.02	4
1979	44.8	2.93	43	17.72	4.29	42
1980	57.9	3.78	29	28.07	6.80	58
1981	64.7	4.23	12	35.24	8.53	25
1982	56.3	3.68	-13	31.87	7.72	-9
1983	54.5	3.56	-3	28.99	7.02	-9
1984	55.6	3.63	2	28.94	7.01	0

^aThe five oil-based chemicals are acetic anhydride, benzene, cyclohexane, ethylene, and toluene.

^bThe price per barrel for crude oil is a composite figure of crude oil cost in the U.S. from both foreign and domestic prices.

TABLE 9-3. COMPARISON OF PRICE INDEXES BETWEEN NATURAL GAS AND THE
AVERAGE PRICE OF FIVE GAS-BASED CHEMICALS^a 1970-1984^{17 18}
(Base year = 1973)

Year	Five gas-based chemicals			Natural gas		
	Average price, \$/kg	Index	Percent change in index	Price, ^b \$/mcf	Index	Percent change in index
1970	23.1	1.02		--	--	--
1973	22.7	1.00	-2	0.35	1.00	--
1974	29.5	1.30	30	0.49	1.40	40
1975	36.0	1.59	2	0.77	2.20	57
1976	39.9	1.76	11	1.06	3.03	38
1977	38.2	1.68	-5	1.33	3.80	25
1978	40.9	1.80	7	1.48	4.23	11
1979	49.7	2.19	22	1.80	5.14	22
1980	59.2	2.61	19	2.28	6.51	27
1981	64.1	2.82	8	2.91	8.31	28
1982	65.6	2.89	2	3.49	9.97	20
1983	77.6	3.42	18	3.58	10.23	3
1984	88.0	3.88	13	3.69	10.54	3

^aThe five gas-based chemicals are acetylene, carbon disulfide, methyl chloride, methylene chloride, and phosgene.

^bThe price for Natural gas is the purchase price for Electric plants in 10⁶ ft³. This price was chosen to more closely portray the cost that might be incurred by an industrial consumer of a feedstock.

materials to total sales is expected to increase in the future because petroleum and agricultural input costs are rising at a percentage rate greater than that of the overall rate of inflation.²⁰

Capital Requirements of the Chemical Industry. The chemical industry is very capital intensive. Due to the high rate of process innovation and product development in the industry, plants become obsolete relatively quickly. Maintenance and repair of buildings and facilities is also an important input for the industry. Capital expenditures for the chemical industry were \$8.14 billion in 1977, or 5.2 percent of sales.²¹ (The return on investment was \$1.55 for every dollar invested in industrial chemicals and synthetics in 1979, as compared to \$1.60 for the manufacturing sector as a whole.²¹) Table 9-4 shows that capital expenditures for the industry are increasing over time. After a sharp drop in investment during the 1982 recession, spending for 1983 is expected to have increased.²¹

Employment. Historical employment figures for SIC 286 are presented in Table 9-5.^{22,23} Employment rose during the period of increasing production from 1958 to 1969 and then remained relatively stable from 1970 to 1975. For the broader category Chemicals and Allied Products (SIC 28), employment remained stable from 1980 to 1981, but fell 3 percent in 1982; employment in all manufacturing fell 7 percent from 1981 to 1982.²⁴

The number of employees in chemical production has decreased while the unit costs for labor have increased in recent years. Unit labor costs increased by nearly 13 percent from 1981 to 1982.²⁵ Historically, although unit labor costs increased, these increases were offset by corresponding increases in productivity. However, since the late 1970s, productivity increases have not kept up with unit labor costs. Table 9-6 provides indices for productivity and unit labor costs for 10 years for chemicals and allied products and for all manufacturing industries.²⁵ Until 1982, the chemical industry generally performed better than manufacturing as a whole in terms of labor productivity; however, in 1982, chemicals' productivity slipped 3 percent while manufacturing productivity gained 3 percent. Compared to the sharp increase in unit labor costs for chemicals, manufacturing unit costs rose only 3 percent.

Since the chemical industry is relatively capital intensive, the value of annual sales per employee is quite high. The Kline Guide reports that, for chemicals as a whole, this value per employee was \$143,000 in 1977, compared to \$73,000 for all manufacturing. For basic and intermediate organic chemicals (including cyclic crudes and intermediates, gum and wood chemicals, and other organics), this ratio was particularly high, with a value of \$197,000 per employee.²⁰

9.1.2.2 Demand Conditions.

9.1.2.2.1 Markets for chemicals. A wide variety of markets require chemical inputs. The largest market is the chemical industry itself;

TABLE 9-4. CAPITAL EXPENDITURES IN U.S. FOR CHEMICALS AND ALLIED PRODUCTS INDUSTRY AND ALL MANUFACTURING, 1973-1983 (\$109)^{a 21}

Year	Capital expenditures	
	Chemicals and allied products	All manufacturing
1983	13.69 ^b	115.90 ^b
1982	13.27	119.98
1981	13.60	126.79
1980	12.60	115.81
1979	10.78	98.68
1978	8.46	79.72
1977	8.14	69.22
1976	8.12	59.95
1975	7.63	54.92
1974	6.48	53.21
1973	4.24	42.37

^aCurrent dollars.

^bPreliminary estimate.

TABLE 9-5. NUMBER OF COMPANIES, ESTABLISHMENTS, AND EMPLOYEES
FOR INDUSTRIAL ORGANIC CHEMICALS, 1958-1981^{22 23}

Year	Companies ^a	Establishments ^b	Employees, 10 ³
1981			147.5
1977	623	866	152.8
1972	690	826	135.8
1967	626	849	131.0
1963		841	120.0
1962	629		115.3
1958		639	113.9

^aA company is a business organization consisting of one establishment or more under common ownership or control.

^bAn establishment is a place where a product is produced or distributed or a service rendered. The principal product or service defines the establishments type, i.e., SIC. One physical location may have several establishments, but typically each establishment has only one location.

TABLE 9-6. PRODUCTIVITY AND UNIT LABOR COSTS^a IN U.S. FOR CHEMICALS AND ALLIED PRODUCTS INDUSTRY AND ALL MANUFACTURING, 1972-1982²⁵

Year	Chemicals and allied products		All manufacturing	
	Productivity	Unit labor	Productivity	Unit labor
1982	197.5	163.0	163.3	184.0
1981	203.2	144.8	157.8	178.9
1980	196.5	136.2	152.5	168.5
1978	184.8	122.6	144.3	151.1
1976	168.5	114.0	134.5	132.7
1974	151.7	103.8	129.2	121.1
1972	143.2	95.9	122.2	110.9

^aIndex, 1967 = 100

other markets include those for plastics, synthetic rubber, organic fibers, paints and allied products, and petroleum refining.¹⁶ Because the chemical industry provides inputs for a wide variety of other industries, demand for chemicals tends to follow that of the entire economy. During 1982, for example, when housing and automobile markets were poor, chemical sales dropped 8 percent. They began to recover in 1983 as key markets began to rebound.²⁶ Table 9-7 presents historical production and sales data for several USITC categories of organic chemicals.²⁷ These data illustrate the relationship between chemical production and economic trends. Drops in production and sales occurred between 1974 and 1976 and 1980 and 1981, periods of recession in the U.S. economy.²⁸ Rapid production and sales increases tend to follow recessionary periods.

The elasticity of demand is a measure of the percentage change in quantity demanded in response to a change in price. A recent USITC document cites an unpublished demand elasticity of -0.7 to -0.9 for chemicals and allied products.²⁹ Values in this range are reasonable from a theoretical perspective because the largest sectors within the industry make producer goods. Thus, because other industries need these chemicals to produce their products, overall chemical industry price increases will not lead to proportional decreases in consumption. Demand for individual chemicals, however, may be more elastic if substitutes are readily available at comparable cost.

9.1.2.2.2 Foreign trade conditions. The foreign trade position of the United States in chemicals has traditionally been strong. Table 9-8 presents a time series of U.S. exports and imports for all chemicals and for the subset of organic chemicals.³⁰ To establish this time series, nominal dollar values have been converted to real dollar values using a chemical and allied products industry producer price index.³¹ The table shows that total revenues for exports grew consistently through the 1970s, although imports have grown more steadily in recent years. Although overall demand slowed in 1982, reflected in decreases in real revenues of both exports and imports, the United States has maintained a favorable balance of trade in chemical sales. In 1982, \$19,891 million (in current dollars) in chemicals were exported; only \$9,494 million (in current dollars) were imported. Organic chemicals show a similar pattern.

The United States enjoyed a cost advantage in chemical production prior to 1981 because of Federal price controls on petroleum products. Decontrol of oil in 1981 and staged decontrol of natural gas have eroded this advantage, however, and U.S. producers are now beginning to face increasing foreign competition in chemicals trade. Industry experts predict that export markets will shrink as new plants are built in Canada, Mexico, and OPEC nations, all of which have ready access to inexpensive raw materials.³² A recent USITC study notes that nations with a manufacturing cost advantage in production of crude petroleum and natural gas, such as Saudi Arabia, Indonesia, Kuwait, Canada, and Mexico, might pose a significant threat to U.S. markets. These nations have the necessary infrastructure, ample petroleum resources, and low energy consumption. In addition, the price in some of these nations for

TABLE 9-7. HISTORICAL PRODUCTION AND SALES OF INDUSTRIAL ORGANIC CHEMICALS, 1955-1981^a

Year	Production, Gg	Sales quantity, Gg	Sales value, \$10 ^{6b}
1981	77,500	33,800	30,995
1980	77,800	34,900	29,057
1979	82,100	36,300	26,007
1978	64,600	30,000	19,397
1977	61,200	29,100	17,945
1976	60,200	27,900	16,557
1975	61,000	29,000	15,355
1974	71,800	34,900	15,245
1973	69,900	36,200	10,049
1972	65,600	33,300	8,558
1971	57,700	28,600	7,592
1970	57,800	28,100	7,381
1969	56,800	27,400	7,277
1968	51,400	24,700	7,047
1967	45,700	21,700	6,359
1966	44,300	20,800	5,762
1965	40,100	19,000	5,182
1964	36,300	17,500	4,697
1963	32,500	15,100	4,210
1962	30,100	14,200	4,082
1961	27,600	13,400	4,040
1960	27,100	12,900	3,672
1959	25,000	12,300	3,498
1958	24,900	11,900	3,039
1957	26,700	12,700	3,097
1956	27,800	12,600	3,008
1955	23,500	11,900	2,811

^aThese figures are based on a summation of the following International Trade Commission categories: tar, tar crudes, cyclic intermediates, dyes, lakes and toners, flavor and perfume materials, rubber-processing chemicals, plasticizers, pesticides, miscellaneous end-use chemicals, and miscellaneous cyclic and acyclic chemicals. These groupings are not strictly comparable to similar SIC groupings.

^bCurrent dollars.

TABLE 9-8. U.S. FOREIGN TRADE FOR INDUSTRIAL ORGANIC CHEMICALS,
1972-1982 (\$10⁶)^{a30}

Year	Exports		Imports		Ratio (exports/imports)	
	Organic chemicals	All chemicals	Organic chemicals	All chemicals	Organic chemicals	All chemicals
1982	1,990	7,279	1,083	3,474	1.84	2.09
1981	2,214	7,912	1,111	3,527	1.99	2.24
1980	2,351	8,557	1,048	3,546	2.24	2.41
1972	1,134	4,134	517	2,015	2.19	2.05

^aReal dollars, base year = 1972.

natural gas, a feedstock and energy source for some primary petrochemicals, may be only 10 to 20 percent of that in the United States. With feedstock and energy costs for chemicals such as methyl alcohol and ethylene comprising 60 to 70 percent of production costs, the cost advantage for these nations is tremendous.³³

A key factor in the impact of the entry of these nations into the world market is their method of entry. If these energy-rich nations require their crude oil customers to buy petrochemicals, or if they cut prices substantially, they could reduce the market shares of existing U.S. producers. If their entry is linked to demand increases, however, the impact will not be as large. Additionally, many U.S. producers now are finding it cheaper to import basic and intermediate chemical inputs to produce end-product chemicals. Although costs are held down by this practice, it worsens the overall U.S. trade balance. Some U.S. firms are considering mergers and joint ventures with foreign producers.³³

As a potential result of the loss of key export markets, the USITC study concludes that, by 1990, the United States could have a net chemical trade imbalance with about 120,000 Mg of exports and 4.8 million Mg of imports compared to current large net export surpluses.³⁴ This shift might cause substantial decreases in output in the chemical and allied products industry of \$190 million to \$5.1 billion in 1990, with an accompanying loss of up to 24,396 jobs in the industry.³⁵

However, several factors should allow U.S. producers to retain some trade advantage over the energy-rich nations. First, decontrol of gas is a phased process and will not be complete even in the mid-1980s.³⁶ Second, the U.S. chemical industry has an efficient interplant distribution network and better marketing and research and development technology in some cases. Therefore, many U.S. plants are currently being constructed with flexibility in the use of raw materials and will therefore be able to select the least expensive inputs at any particular time.³⁷ Foreign producers may be more restricted in their selection of raw materials, such as crude oil, naphtha, and various basic chemicals.

The United States is protected from organic chemical imports by high tariffs. This is true especially for the benzenoid imports category, which contains many of the organic chemicals. The benzenoid group includes any chemical whose molecular structure has one or more six-membered carbocyclic or heterocyclic rings with conjugated double bonds (e.g., benzene or pyridine rings). Until recently, tariff valuation for some benzenoid chemicals was extremely protective under the American Selling Price (ASP) system. The ASP customs valuation system in some cases led to a tariff representing approximately 20 percent or more of the selling price of imports, making it difficult for foreign producers to sell to the United States at a profit.

Recent multilateral trade negotiations scrapped the ASP system and replaced it with a new set of tariffs that became effective July 1, 1980.

Tariff rates for all chemicals have now been set on the basis of "transaction value," which is the foreign invoice price plus shipping and insurance. Many benzenoid chemicals do not have large tariff reductions under the new tariff system.³⁸ These benzenoid chemicals represented a \$226 million portion of the \$688 million in dutiable benzenoid imports during 1976. The average U.S. duty rate for non-benzenoid chemical imports will be a little over 7 percent by 1987 when the new rates are fully phased in.³⁹

U.S. producers do face occasional problems in competing with government-subsidized non-U.S. producers or in exporting to regulated non-U.S. markets. These factors in combination with the large cost advantage in the use of feedstocks and petroleum-based inputs have the potential of reversing the trend of consistent balance of trade surpluses that the U.S. experienced in the world chemical markets throughout the 1970s. These problems, however, should not prevent the continuation of a chemical balance of trade surplus through the next 5 years, given the continuing favorable treatment of many benzenoid products in the new tariff system, the relatively small decrease in most tariff rates, and the flexibility in use of inputs that many U.S. chemical producers have.

9.1.3 Market Structure

The structure of the chemical industry as a whole, and especially the sector producing the large-volume chemicals, is the subject of this section. The firms that produce the chemicals, as well as the number, size, and distribution of the plants at which they are produced, are discussed, and the relationship between these firms and plants is analyzed.

9.1.3.1 Chemical Firms. There are about 1,500 firms that produce chemicals and allied products. Among these is a wide range of firm types, from those that produce only chemicals to others that produce a variety of products. Major producers include Allied, Celanese, Dow Chemical, Du Pont, Monsanto, Shell, and Union Carbide. These companies each produce many different chemicals at several locations. In contrast, several companies produce just one chemical at a single location. Table 9-9 lists the chemical sales and the ratio of chemical sales to total sales for the 25 largest chemical producers.⁴⁰ A detailed list of the firms and plants currently producing the reactor processes chemicals is given in a memorandum to the Docket created and maintained as an official record of the reactor processes standards development effort.⁴¹

9.1.3.2 Geographic Distribution, Number, and Size of Plants. Table 9-10 presents the number of plants, capacity ranges, and general locations for the large-volume chemical plants.⁴¹ The manufacture of the organic chemicals is concentrated in the States of Texas and Louisiana.

Plant capacities for the production of large-volume chemicals vary widely, from under 500 kg/yr to more than 2,000 Gg/yr. Basic and intermediate chemicals are generally produced at larger capacity plants.

TABLE 9-9. TOP 25 U.S. CHEMICAL PRODUCERS, 1982⁴⁰

Rank	Company	Chemical sales, \$10 ⁶	Chemicals as percentage of total sales
1	Du Pont	10,841	32.5
2	Dow Chemical	8,252	77.7
3	Exxon	7,259	7.1
4	Monsanto	5,737 ^a	90.7
5	Union Carbide	4,985	55.0
6	Shell Oil	3,085	15.4
7	Celanese	3,062	100.0
8	Standard Oil (Indiana)	2,786	9.4
9	W. R. Grace	2,654	43.2
10	Allied	2,407	39.0
11	Phillips Petroleum	2,356	15.0
12	Atlantic Richfield	2,242	8.3
13	Eastman Kodak	2,151	19.9
14	Mobil	2,148	3.3
15	Hercules	2,040	82.6
16	Gulf Oil	2,006	6.6
17	Rohm & Haas	1,727	94.5
18	American Cyanamid	1,698 ^a	49.2
19	Stauffer Chemical	1,618	100.0
20	American Hoechst	1,506 ^a	100.0
21	Texaco	1,497	3.2
22	Ethyl	1,411	87.4
23	Air Products	1,359	86.6
24	FMC	1,319	37.7
25	Ciba-Geigy	1,285	68.0

^aChemical sales include significant amounts of nonchemical products.

TABLE 9-10. NUMBER, CAPACITY, AND LOCATION OF PLANTS PRODUCING
THE 173 REACTOR PROCESSES CHEMICALS IN 1982⁴¹

Chemical	Number of plants	Plant capacities, Gg/yr ^a			Predominant location
		Smallest	Largest	Median	
Acetaldehyde	2	181	272	227	Texas
Acetic acid	10	41	454	181	Texas
Acetic anhydride	5	63	227	113	Texas
Acetone	14	25	318	100	Texas
Acetone cyanohydrin	NDA				
Acetylene	7	5	82	9	Texas, Louisiana
Acrylic acid	4	18	159	88	Texas
Acrylonitrile	6	113	209	181	Texas
Adipic acid	4	14	317	236	Texas
Adiponitrile	6	23	227	227	Texas
Alcohols (C-11 or lower, mixtures)	NDA				
Alcohols (C-12 or higher, mixtures)	5				
Alcohols (C-12 or higher, unmixed)	NDA				
Allyl chloride	3	53	120	53	Texas, Louisiana
Amylene	8	0.5	227	14	Texas, Louisiana
Amylenes (mixed)	NDA				
Aniline	6	59	127	120	--
Benzene	55	3	463	99	Texas
Benzenesulfonic acid	7	0.005	227	5	Alabama
Benzenesulfonic acid, mono-C ₁₀₋₁₆ alkyl derivatives, sodium salts	29	0.005	23	23	--

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(continued)

TABLE 9-10 (continued)

Chemical	Number of plants	Plant capacities, Gg/yr ^a			Predominant location
		Smallest	Largest	Median	
Benzyl chloride	3	9	36	36	New Jersey, Illinois
Bisphenol A	4	45	159	85	--
Bivinyll	19	20	236	91	Texas, Louisiana
Brometone	NDA				
Butadiene & butene fractions	NDA				
Butanal	7	36	204	95	Texas, Puerto Rico
Butane	NDA				
Butanes (mixed)	NDA				
1,4-Butanediol	4	27	91	45	Texas
2-Butoxyethanol	4				Texas
Butyl acrylate	5				Texas, Louisiana
n-Butyl acetate	4	9	23	23	Texas, Tennessee
t-Butyl alcohol	3	0.5	454	5	Texas
sec-Butyl alcohol	4	34	159	87	--
n-Butyl alcohol	8	2	145	68	Texas
Butylbenzyl phthalate	5	5	227	227	--
α-Butylene	4	12	91	44	Texas
β-Butylene	8	23	45	34	Texas, Louisiana
Butylenes (mixed)	8	11	225	86	--
t-Butyl hydroperoxide	6				--
2-Butyne-1,4-diol	4	23	227	102	Texas
Butyric anhydride	1				Tennessee
Caprolactam	3	159	218	163	--
Carbon disulfide	4	5	159	70	--
Carbon tetrachloride	9	4	136	41	--

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TABLE 9-10 (continued)

Chemical	Number of plants	Plant capacities, Gg/yr ^a			Predominant location
		Smallest	Largest	Median	
Chloroacetic acid	5	2	23	14	--
Chlorobenzene	3	23	68	68	--
Chloroform	7	16	50	34	Illinois
p-Chloronitrobenzene	2	0.5	45	45	--
Citric acid	5	11	45	39	--
Cumene	11	54	340	181	Texas
Cumene hydroperoxide	5	0.05	227	5	--
Cyanuric chloride	4	0.5	45	14	--
Cyclohexane	10	35	259	121	Texas
Cyclohexane, oxidized	2	45	227	227	Texas
Cyclohexanol	7	23	227	227	Texas
Cyclohexanone	6	9	331	181	Texas, Florida
Cyclohexanone oxime	4				--
Cyclohexene	5				--
1,3-Cyclopentadiene	NDA				--
Diacetone alcohol	4				--
1,4-Dichlorobutene	4				Louisiana, Texas
3,4-Dichloro-1-butene	NDA				
Diethanolamine	NDA				
Diethylbenzene	2				Michigan, Louisiana
Diethylene glycol	14	2	54	20	Texas, Louisiana
Diisodecyl phthalate	6				
Dimethyldichlorosilane	2				Michigan, West Virginia
Dimethylterephthalate	5	227	590	249	North Carolina, Tennessee

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TABLE 9-10 (continued)

Chemical	Number of plants	Plant capacities, Gg/yr ^a			Predominant location
		Smallest	Largest	Median	
2,4-(and 2,6-)Dinitrotoluene	4				Texas, West Virginia
2,4-Dinitrotoluene	5				--
Diocyl phthalate	7	14	113	45	--
Dodecene	7	8	120	18	--
Dodecylbenzene, linear	5	18	102	73	--
Dodecylbenzene, nonlinear	3		102	-	California
Dodecylbenzenesulfonic acid	27				--
Dodecylbenzenesulfonic acid, sodium salt	48				--
Epichlorohydrin	2	100	191		Texas
Ethanolamine	5	11	109	57	Texas, Louisiana
Ethyl acetate	6	7	36	15	Texas
Ethyl acrylate	5				Texas, Louisiana
Ethyl alcohol (synthetic)	4	75	359	188	--
Ethylbenzene	14	16	846	318	Texas, Louisiana
Ethyl chloride	5	34	95	54	Louisiana, Texas
Ethylene	23	45	2177	544	--
Ethylene dibromide	4				Arkansas, Texas
Ethylene dichloride	18	68	908	454	Louisiana, Texas
Ethylene glycol	14	23	612	181	--
Ethylene glycol monoethyl ether	4	23	23	23	--
Ethylene glycol monoethyl ether acetate	3				Texas, Tennessee
Ethylene oxide	15	50	590	204	Louisiana, Texas
2-Ethylhexyl alcohol	5	25	77	32	Texas

(continued)

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TABLE 9-10 (continued)

Chemical	Number of plants ^a	Plant capacities, Gg/yr ^a			Predominant location
		Smallest	Largest	Median	
(2-Ethylhexyl) amine	4				--
6-Ethyl-1,2,3,4-tetrahydro-9,10-anthracenedione	NDA				
Fluorocarbon 113	5	5	45	25	--
Formaldehyde	15	27	925	186	--
Freon 11	12 ^b				
Freon 12	12 ^b				
Freon 21	3				--
Freon 22	12 ^b				
Glycerin (synthetic)	2	18	52		Texas
Heptane	11	0.0005	227	0.5	--
Heptenes (mixed)	3	14	27	27	Delaware, Louisiana
Hexane	4				--
Hexamethylene diamine	8	0.0005	227	136	Texas
Hexamethylene diamine adipate	2				South Carolina, Florida
Hexamethylene tetraamine	6	4	14	11	--
Isobutane	NDA				
Isobutyl alcohol	8	7	25	13	Texas
Isobutylene	4	7	127	101	Texas, Louisiana
Isobutyraldehyde	7	7	91	14	Texas
Isopentane	44	0.0005	454	23	Texas
Isoprene	8	23	84	27	Texas
Isopropyl alcohol	6	23	454	206	Louisiana, Texas

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TABLE 9-10 (continued)

Chemical	Number of plants ^a	Plant capacities, Gg/yr ^a			Predominant location
		Smallest	Largest	Median	
Ketene	1				West Virginia
Linear alcohols, ethoxylated (mixed)	19				--
Linear alcohols, ethoxylated and sulfated, sodium salt (mixed)	13				--
Maleic anhydride	7	5	59	27	--
Methyl alcohol	12	174	748	434	Texas, Louisiana
Methylamines	4	5	75	39	--
ar-Methylbenzenediamine	NDA				
Methyl chloride	9	11	68	29	Louisiana, W. Virginia
Methyl chloroform	3	91	204	159	Louisiana, Texas
Methylene chloride	7	27	159	50	--
Methyl ethyl ketone	6	36	136	45	--
Methyl isobutyl ketone	5	7	36	18	--
Methyl methacrylate	4	54	340	95	--
Mesityl oxide	7	0.5	23	3	--
2-Methylpentane	NDA				
1-Methyl-2-pyrrolidone	3				--
Methyl t-butyl ether (MTBE)	10	25	318	98	Texas
Naphthene	9	34	45	41	--
Nitrobenzene	6	34	170	153	--
Nonyl alcohol	1				New Jersey

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(continued)

TABLE 9-10 (continued)

Chemical	Number of plants	Plant capacities, Gg/yr ^a			Predominant location
		Smallest	Largest	Median	
Nonylphenol	6	5	27	14	--
Nonylphenol, ethoxylated	16				--
Octene	4				Texas
Oil-soluble petroleum sulfonate, calcium salt	7				--
3-Pentenitrile	NDA				
Pentaerythritol	4	11	34	19	--
Pentenenes (mixed)	NDA				
Perchloroethylene	7	23	109	68	Louisiana, Texas
Phenol	10	34	236	196	--
1-Phenylethyl hydroperoxide	NDA				
Phenylpropane	2	0.0005	227		Texas
Phosgene	16	11	122	57	--
Phthalic anhydride	9	36	106	77	--
α -Pinene	9				Florida
Propanal	3				Texas
Propane	NDA				
Propyl alcohol	3	29	38	32	Texas
Propylene	30				
Propylene glycol	6	23	113	57	--
Propylene oxide	4	200	590	322	Texas, Louisiana
Sorbitol	7	5	57	36	--
Styrene	12	54	680	324	Texas, Louisiana
Terephthalic acid	7	195	907	454	South Carolina, Alabama

Footnotes on last page of table.

(continued)

TABLE 9-10 (continued)

Chemical	Number of plants	Plant capacities, Gg/yr ^a			Predominant location
		Smallest	Largest	Median	
Tetraethyl lead/tetramethyl lead	4	36	79	54	Texas, Louisiana
Tetrahydrofuran	3	23	45	34	--
Tetra (methyl-ethyl) lead	NDA				
Toluene	28				--
Toluene-2,4-diamine	10				--
Toluene-2,4-(and 2,6-) diisocyanate (80/20 mixture)	7	18	57	50	--
Trichloroethylene	2	54	100		Texas, Louisiana
Triethanolamine	NDA				
Triethylene glycol	12	1	11	7	Texas, Louisiana
Trimethylene	NDA				
Tripropylene	5	11	145	38	--
Vinyl acetate	5	181	272	193	Texas
Vinyl chloride, monomer	12	136	567	361	Louisiana, Texas
Vinylidene chloride	5	0.5	227	45	Louisiana, Texas
Vinyl trichloride	7	5	227	45	Louisiana, Texas
Xylenes (mixed)	23				--
m-Xylene	1			79	Texas
o-Xylene	7	11	136	59	Texas
p-Xylene	10	27	1,089	204	--

^aSources of data are Mansville Chemical Synopsis, Chemical Marketing Reporter, Toxic Substances Control Act Surveys, and SRI Directory of Chemical Producers.

^bFreon 11, 12, and/or 22 can be manufactured at these plants.

NDA = No data available for the chemical.

End-product chemicals, which are produced in smaller quantities and at higher prices, are more likely to be produced at smaller plants. Plants that produce less than 1 Gg/yr do not add significantly to total national production or to resulting VOC emissions. These plants do not contribute significantly to national emissions levels because of a proportional relationship between production and emissions levels. Because this standard is limited to chemicals whose total annual production exceeds 45.4 Gg/yr, it is assumed that plants producing less than 2.5 percent of that minimum (less than 1 Gg) do not add significantly to total national emissions levels resulting from the production of all 173 large-volume chemicals. Consequently, these small plants are ignored in the economic analysis that follows in Sections 9.2 and 9.3, although they are shown in Table 9-10. Furthermore, it is assumed here that the projected new plants that will be affected by these proposed standards will each produce at least 1 Gg/yr.

9.1.3.3 Firm Concentration. The chemical industry is dominated by a few major producers. It is estimated that 23 percent of total industry sales are attributable to the top four companies and 40 percent to the top ten.⁴² While this concentration level is relatively high compared to manufacturing industries, it is low compared to other capital-intensive industries, such as motor-vehicle production and petroleum refining.⁴³

Although the industry as a whole is rather concentrated, the sectors within it have varying levels of concentration. For example, in gum and wood chemicals (SIC 2861), the top four firms account for more than 70 percent of shipments. In contrast, the top four companies account for less than 40 percent of shipments in the detergent and surfactants sector.⁴³

Concentration in the production of each of the reactor process chemicals is difficult to assess. Production of some chemicals is quite unconcentrated; benzene is produced by a large number of producers at different locations. In contrast, 90 percent of benzyl chloride production is at two plants owned by a single firm.

9.1.3.4 Vertical Integration and Diversification. As indicated in Section 9.1.1, vertical integration among industry firms has been encouraged by the basic structure of the chemicals industry. Diversification into the production of nonchemical goods or services by chemicals companies has also been common. The Kline Guide reports that, prior to World War II, most companies producing chemicals were engaged only in the production of chemical products. Since that time, however, forward vertical integration by petroleum and other companies seeking the higher profits associated with chemicals made from their products has changed this. Currently, only 37 of the 100 largest chemical producing companies have more than 50 percent of their sales in chemical products. Of the top 25 companies listed in Table 9-9, for example, 8 are petroleum companies.⁴⁰ Petroleum companies now account for over 25 percent of chemical production in the United States.⁴⁰

Diversification was first encouraged by the decline in profits that the industry began experiencing following the boom period of the 1960s. This trend is discussed in a later section of this profile. Many chemical companies have branched out into technical nonchemical areas. This trend is expected to continue as higher costs and decreasing profit margins continue in the industry.⁴⁴

9.1.3.5 Returns to Scale. The average cost of production may change as a firm changes its production capacity. If average cost declines with increases in a firm's capacity, production is said to exhibit increasing returns to scale; if average costs increase with increases in a firm's capacity, production is said to exhibit decreasing returns to scale. In general, as a plant's capacity increases, the plant is expected to experience first increasing, then constant, and, finally, decreasing returns to scale. In a competitive business environment, firms prefer a plant capacity in the constant-returns-to-scale size range since that size minimizes average costs of production. With market demand sufficiently large relative to the constant-returns-to-scale plant size, i.e., the cost-minimizing plant capacity--numerous competitive firms will likely be able to operate at optimal, cost-minimizing conditions. With small market demand relative to a cost-minimizing capacity size, however, there is a tendency for one or a few firms to take advantage of the low cost of constant-returns-production and dominate the market. At issue, then, is whether the markets for the affected chemicals are large relative to the firm's cost-minimizing plant capacity. If market demand is sufficiently large, then many firms experience constant returns to scale and there is no impediment to the operation of perfectly competitive markets in chemical production. The size of optimum plant capacity compared to total market size is the important consideration for assessing the role of returns to scale in effecting market competition.

As discussed in Section 9.1.3.3, there is no clear pattern relating plant capacity and market size in the SOCOMI industry as a whole. Production of many basic and intermediate chemicals appears to exhibit increasing returns to scale because the chemicals are most often produced at large-scale plants. The markets for some of these chemicals are large enough, however, to support quite a few large-scale plants. On the other hand, some chemicals are produced at relatively small plants. Since some of these plants serve a relatively small market, however, only a very few may be able to produce at a minimum average cost and survive, thus possibly reducing competition between the firms operating the plants.

Table 9-8 shows that, for the 153 chemicals for which data on the number of producing plants are available, 98 are produced at at least five locations. These data suggest that, for a large number of affected chemicals, increasing returns to scale have not resulted in very few plants. As to whether the industry may have an imperfectly competitive structure for other reasons, considerations such as the number of firms in the market, the barriers to entry, and the availability of substitutes are the relevant measures to consider. These issues are discussed in Section 9.1.4.

9.1.3.6 Industry Cost Structure. The average cost of production for firms in an industry may change as industry-wide output changes. These changes in cost can occur because input prices may change when all the firms in the industry act in concert to increase or decrease production. An industry is said to be an increasing, decreasing, or constant-cost industry if the expansion of industry output increases, decreases, or does not affect average total costs of production. These distinctions are important because they affect what proportion of the control costs of a regulation is passed through to customers in the form of a price increase. The average costs of control may be less than, greater than, or just equal to the change in price caused by a regulatory alternative, depending on whether the industry is an increasing, decreasing, or constant cost industry.

With the data available, it is very difficult to determine how changing SOCOMI industry output has affected chemical prices. In essence, there are other changes that occur that can also account for price changes. For example, between 1960 and 1979, physical output in the industry increased at an average rate of 7.5 percent per year. Until 1973, prices for chemicals decreased consistently. This suggests a decreasing cost structure for the industry, but it could just as well reflect improved industry technology. After 1973, price indices began to rise, apparently due to increasing input costs that were not offset by productivity increases. However, this response is also consistent with an increasing cost industry. Given this uncertainty, and the ambiguous history of price changes associated with increasing output, the SOCOMI industry is treated in this analysis as a long-run constant cost industry. This means that, in a competitive environment, the average cost of control will be equal to the change in price due to the regulation.

9.1.3.7 Entry Conditions. Although ease of entry into the chemical industry cannot be measured directly, some general comments can be made. Firms now considering entering the industry face high initial capital costs, as well as barriers of technical expertise. However, because many firms have historically diversified into chemicals and because the number of firms in the industry is large, these barriers have not been insurmountable. Therefore, barriers to entry are probably not a major threat to the competitive nature of the chemical industry. An NSPS would increase the initial capital costs of entering the industry, but control costs would not discourage entry because they are a very small proportion of total capital costs.

9.1.4 Pricing

Market structure, particularly industrial concentration and barriers to entry, and the homogeneity or heterogeneity of a chemical product influence the competitiveness of firms producing that chemical and, therefore, the pricing practices of those firms. Pricing practices, in turn, indicate how firms may try to pass control costs forward.

9.1.4.1 Homogeneity of Product. The more the output of an industry is perceived by demanders to be homogeneous, the more likely a single market price will be observed.

No generalization can be made about the homogeneity of chemical products as a whole. Some chemicals are commodities produced by a large number of producers to standard specifications of general usage, such as basic chemicals, which have an average of 25 producers each. (Economists use the term "commodity" to describe any item that is produced by a large number of producers to standard specifications.) Price increases on the part of a single producer would render its products uncompetitive because little product differentiation is evident. In contrast, most end-product chemicals are produced to perform a specific function. Companies with a degree of expertise in production would be in a much better position to raise their prices without losing customers. The reactor process chemicals are produced in large quantity, and most of them are commodity chemicals that can be characterized by the more competitive environment described above.

9.1.4.2 Degree of Concentration and Barriers to Entry. The degree of concentration of industrial output in the largest firms also determines pricing behavior. Different types of chemicals are produced in very different settings, making a characterization of the concentration of the industry difficult.

As discussed in Section 9.1.3.3, some organic chemical groups are rather unconcentrated. Thus, a more competitive environment may exist for these chemicals than for chemicals produced by only a few producers. Of the chemicals with specific production capacity data by firm, 66 percent have no one firm with more than half the total output capacity.⁴¹ In contrast, 11 percent of the chemicals have one firm that dominates the production capacity with more than 90 percent of total capacity. The other 23 percent have one firm maintaining a majority of production capacity, though not monopolizing the output for those chemicals.

In terms of firm concentration in the entire industry, the top ten firms account for about 40 percent of total sales. Though this is a high concentration in comparison to other industries, it is rather low when compared to other capital-intensive industries. For example, the top eight firms in the automobile industry make 99 percent of all vehicles. The top eight firms account for 98 percent of copper shipments, 89 percent of aircraft, 65 percent of primary steel, and 56 percent of petroleum refining.⁴³

Since most chemical producers are primarily involved in other industries (namely, the petroleum, natural gas, and steel industries), entry into the chemicals industry can occur in a variety of ways. Throughout the mid-1960s, the industry enjoyed premium profits, inciting a number of capital-intensive firms to purchase other chemical companies or to diversify their own production. As profits dropped through the 1970s, this practice reversed, so existing chemical companies began to diversify into other production practices--end-use products, for example.⁴⁴ Since the chemical interests of the top companies vary in scope and dimension, the power these companies have on price control is limited. The primary barrier to entry seems to be sufficient funds to either build a new plant and buy new equipment or to buy into a chemical firm

in an attempt to diversify. Most new entries into the industry in recent years have been through acquisition or merger.⁴⁴

9.1.4.3 Observed Pricing Practices. Chemical journals and periodicals usually use list prices when reporting the cost of a chemical. Chemical producers typically base their list prices on a full-cost or cost-plus method. The full-cost method involves adding a desired profit margin to estimated unit costs. Cost-plus pricing uses a percentage return on equity instead of a profit margin on sales to calculate product price. When demand is more elastic, and the product can be easily substituted for, producers settle for a lower profit margin. The market price is determined by supply and demand at a particular time. Since these conditions change frequently, producers offer discounts, add surcharges to list prices, or modify other terms of sale to maintain their prices at market levels. Large-quantity purchasers often enjoy lower prices than small-quantity purchasers, and transportation costs may also affect pricing of chemicals.

As mentioned in Section 9.1.2, raw material inputs greatly influence the prices for most chemicals. If an input is in short supply or is diverted to other products with higher priorities, the selling price of the chemical is apt to rise. For example, the OPEC embargo caused prices of oil-based chemicals to rise. Alternatively, if a large amount of new capacity comes on line for a product, the product's price is apt to decrease. When a large share of plant capacity is idle, producers often offer discounts or reduce prices to maintain plant utilization levels.

Another factor also influences pricing of chemicals. Some chemicals experience seasonal variation in demand. Toluene, for example, and other basic aromatics that can be used as octane enhancers in gasoline, experience higher demand in the peak driving seasons of the year. Thus, capacity is more highly utilized during this season, and supply tightens, allowing chemical producers to raise their prices.⁴⁵

Table 9-11 presents historical price index series for chemicals and other manufacturing sectors.⁴⁶ The dramatic rise in chemical prices due to supply shocks is evident in the early 1970s, followed by steady increases in both chemicals and allied products as a whole and in industrial chemicals. The annual real change over the period 1972 to 1982 for chemicals and allied products is 11 percent, while industrial chemicals show a 13-percent annual rise. Industrial commodities and all commodities show a more moderate 10-percent increase. While prices for the commodities and for the chemicals and allied products group continued to rise from 1981 to 1982, prices for industrial chemicals dropped by 3 percent. Record low capacity utilization rates and soft markets due to the recession over the period contributed to the price decline in this sector.

9.1.5 Market Performance

Emphasis in this section is on two aspects of market performance: the finances of the organic chemical industry and recent trends in industry variables.

TABLE 9-11. PRICE INDEXES FOR U.S. CHEMICAL
AND OTHER INDUSTRIES, 1972-1982^{a 46}

Year	Chemicals and allied products	Industrial chemicals	Industrial commodities	All commodities
1982	292.4	353.0	312.3	299.3
1981	287.6	363.3	304.1	293.4
1980	260.3	324.0	274.8	268.8
1979	222.3	264.0	236.5	235.6
1978	198.8	225.6	209.4	209.3
1977	192.8	223.9	195.1	194.2
1976	187.2	219.3	182.4	183.0
1975	181.3	206.9	171.5	174.9
1974	146.8	151.7	153.8	160.1
1973	110.0	103.4	125.9	134.7
1972	104.2	101.2	117.9	119.1

^aProducer price index, 1967 = 100.

9.1.5.1 Financial Profile of the Industry. Profitability and capital structure are two of several measures that indicate the financial health of an industry. Profitability is the measure of a firm's ability to maximize its shareholder's wealth. Capital structure determines the ability of the firm to raise funds for growth and to maintain stable earnings.

Profitability can be assessed in a number of ways. Table 9-12 presents significant financial ratios for SIC categories 2865 and 2869, the two major components of the organic chemicals group. Financial ratios are technical terms that represent measures of an industry's financial health.⁴⁷ The four measures presented provide a means of evaluating the profitability of the organics sector. The first two values presented, which examine the revenue and assets aspects of profitability, are the percentage of net profits to net sales and the percentage of net profits to tangible net worth. The percent of current debt to net worth and the percent of total debt to net worth examine the debt and liability indicators of profitability. Figures 9-1 and 9-2, respectively, show historical trends in the percentage of net profits to net sales and the percentage of net profit to net worth for the chemical industry.^{48,49} Note that the data in the figures are from a different source than the data presented in the tables; therefore the values cannot be directly compared.

The percentage of net profits to net sales and net profits to tangible net worth are primary indicators of profitability. Net profits to net sales is the value of net earnings after taxes divided by net sales. This measure is also referred to as the profit ratio and represents the ability of an industry to produce goods and services at a profit. Figure 9-1 shows that overall profitability increased over the early 1970s but decreased late in the decade. After recovering between 1977 and 1979, the profit measure again fell. Recent sources indicate that the fall in the profit measure has continued into the 1980s, slipping to 4 percent in 1982 from over 6 percent in 1980, reducing the profitability of the industry.⁵⁰

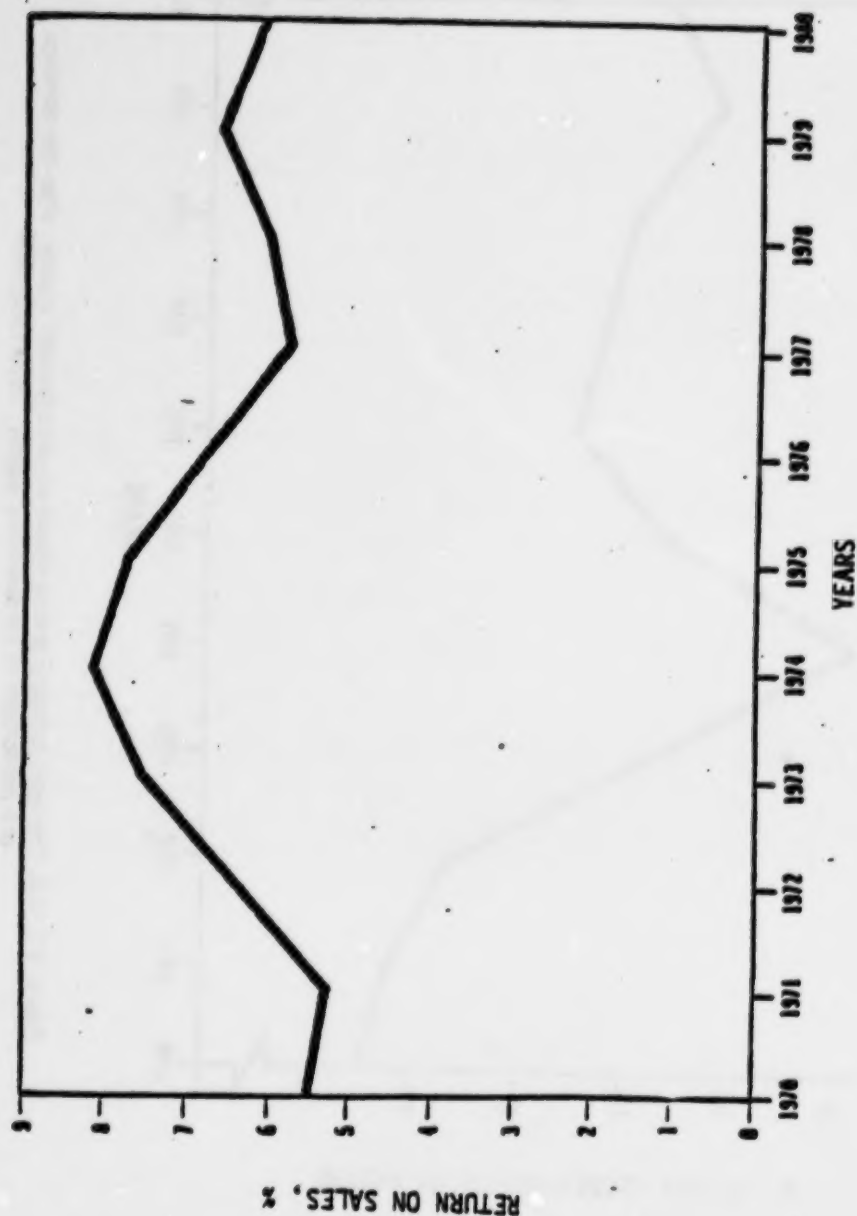
The percentage of net profits to tangible net worth is the value of net earnings after taxes divided by stockholders' equity. Stockholders' equity is obtained by subtracting total liabilities from total assets and then deducting intangibles. Intangibles are certain nonmaterial rights or benefits of a firm and include patents, copyrights, trademarks, and goodwill.⁵¹ A profit-to-equity measure of at least 10 percent is considered necessary to ensure adequate funds for dividends and for future growth.⁵² Both SIC groups have values in excess of 10 percent, although the value for SIC 2869 is larger than that for SIC 2865. Figure 9-2 shows the profit to shareholders' equity ratio for 1970 to 1980. This measure usually varies with the profit ratio measure and is generally considered the key measure of profitability.

The remaining two financial ratios in Table 9-12, the percentages of current debt to tangible net worth and total debt to tangible net worth, are indicators of the debt status of the two SIC groups. The current debt to tangible net worth figure should not surpass 80 percent for a financially

TABLE 9-12. MEDIAN FINANCIAL RATIOS FOR SIC INDUSTRIES
2865 AND 2869, 1980⁴⁷

Median ratio	SIC 2865: Cyclic crudes and intermediates, %	SIC 2869: Industrial organic chemicals, NEC, %
Net profits to net sales	4.57	4.99
Net profits to net worth	17.06	17.28
Current debt to net worth	94.7	41.7
Total debt to net worth	150.9	58.8

NEC = Not elsewhere classified.



Note: Net sales equal gross sales less discounts to customers. Sales are measured before expenses and taxes.

Figure 9-1. U.S. Chemical industry annual profit margin: after-tax earnings as a percentage of net sales, 1970-1980. 48.49

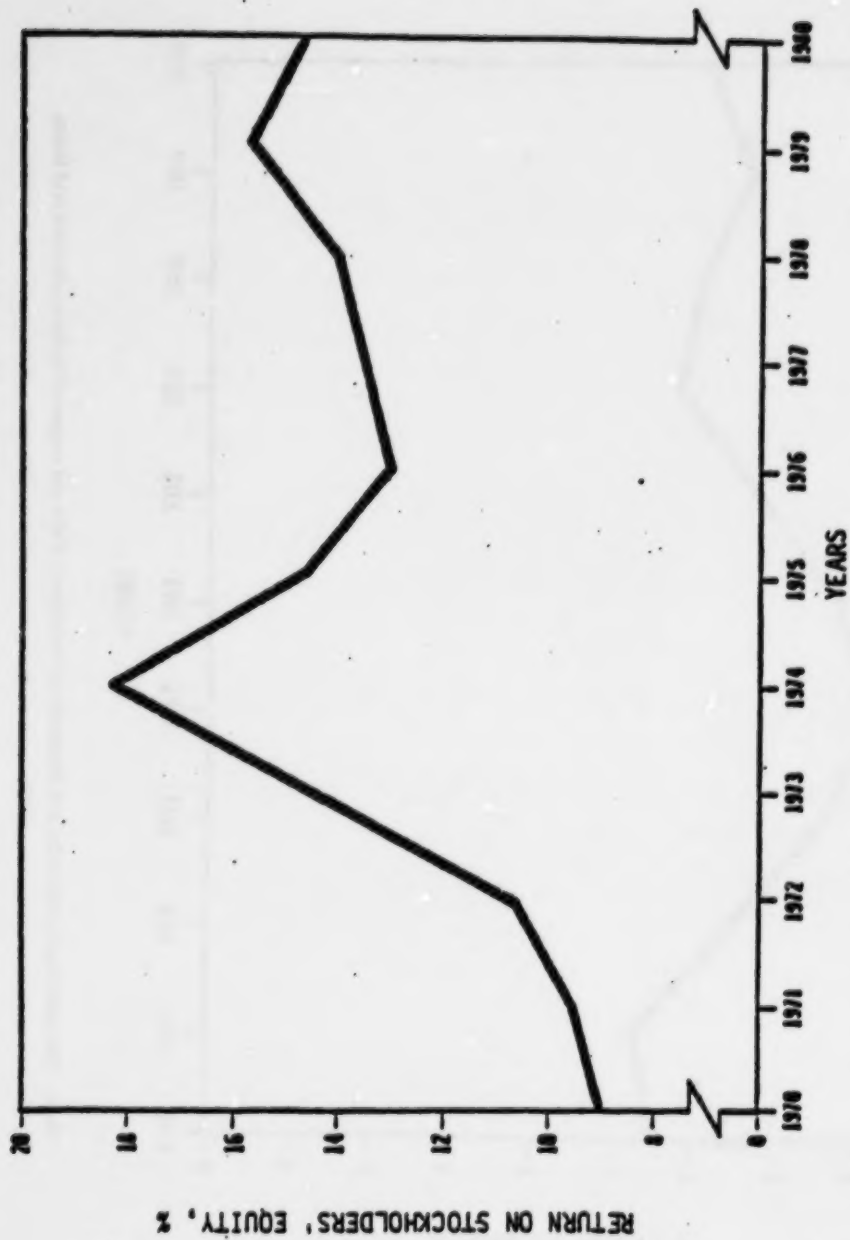


Figure 9-2. U.S. Chemical industry annual return on stockholders' equity: after-tax earnings as a percentage of stockholders' equity, 1970-1980, 48.49

sound firm.⁵³ For example, the cyclic crude and intermediates sector has amassed a substantial amount of current debt compared to its stockholders' equity. The total debt to tangible net worth figure is the percentage of total current plus long-term debt to stockholders' equity. If this measure were to exceed 100 percent, the equity of the firm's creditors would be greater than that of the owners.⁵⁴ Again, SIC 2865 shows less financial stability and demonstrates an overall debt structure that threatens to damage the long-term health of the industry, as this last ratio is more than 150 percent.

Profitability varies among the sectors of the organic chemical industry, however. Commodities are generally more vulnerable to supply and demand shifts than specialty chemicals, while specialty chemicals are generally more profitable than other chemicals. For example, four of the five most profitable chemical manufacturers in 1980 were specialty chemical producers.⁵⁵ Because reactor process chemicals are large-volume chemicals, the financial ratios for the entire industry are most likely representative of the firms producing them. Some financial data for 1982 on the 25 largest firms in the chemical industry are presented in Table 9-13.⁵⁶ (Note that net profit in Table 9-12 is the same measure as operating profit in Table 9-13. Therefore, the operating profit margin for these 25 producers can be compared to the net profits to net sales figure for the whole industry shown in Table 9-12.)

Historically, the chemical industry has maintained its profits by reducing costs while maintaining revenues. This allows firms to operate above the "break-even" point, the point at which total costs and total revenues meet.⁵⁷ The break-even point is lowered when companies reduce fixed costs enough to turn a profit at lower capacity utilization than before. This is done by selling off assets, laying off employees or otherwise lowering labor costs, and eliminating excess inventories.

In addition to profitability, capital structure is a major financial consideration for the chemical industry. Table 9-14 lists the sources of funds for 15 firms within the chemicals and allied products industry over a period of several years.⁵⁴ The industry traditionally has been heavily internally financed. In 1982, 31.5 percent of funds came from depreciation. Long-term debt has become increasingly important for the industry, however, as new, larger scale plants are required. The low net income of the 1980 to 1982 period also contributed to high proportions of debt financing.

Table 9-15 presents debt ratios for the entire chemical industry compared to all manufacturing.⁴⁷⁻⁵⁴ The debt ratio is long-term debt as a percentage of debt plus equity. Table 9-15 shows that the chemicals industry as a whole historically has had debt ratios similar to those of all manufacturing but that these ratios have increased relative to all manufacturing since the late 1970s. Industrial chemicals have had higher debt ratios since the early 1970s. This indicates a trend in the industry toward raising capital externally and, in the process, using up its available source of external funding.

TABLE 9-13. FINANCIAL DATA FOR TOP 25 U.S. CHEMICAL PRODUCERS, 1982

Rank	Company	Chemical operating profit, 10 ⁶ 1982 \$	Change from 1981, %	Chemical operating profits as % of total operating profits	Operating profit margin, % ^b	Tangible chemical assets, 10 ⁶ 1982 \$	Chemical assets, % of total assets	Operating return on chemical assets, % ^c
1	Du Pont	417	-63.7	10.6	3.8	7445	36.6	5.4
2	Dow Chemical	226	-63.1	63.5	2.7	8124	68.8	2.8
3	Exxon	47	-86.5	0.8	0.6	5047	8.1	0.9
4	Monsanto	497	-26.0	99.2	8.7	5234	86.1	9.5
5	Union Carbide	294	-49.3	44.7	5.9	6027	57.3	4.9
6	Shell Oil	-56	Def	Def	Def	3841	18.0	Def
7	Celanese	39	-82.3	100.0	1.3	2862	100.0	1.4
8	Standard Oil (Indiana)	133	-36.7	3.7	4.8	2530	10.6	5.3
9	W. R. Grace	303	-23.5	50.2	11.4	1608	34.5	18.8
10	Allied	105	-50.2	13.4	4.4	1726	27.5	6.1
11	Phillips Petroleum	23	-83.6	1.0	1.0	1563	14.9	1.5
12	Atlantic Richfield	-96	Def	Def	Def	2608	12.1	Def
13	Eastman Kodak	205	-29.1	11.0	9.5	2001	19.3	10.2
14	Mobil	6	-95.1	0.1	0.3	2075	5.8	0.3
15	Hercules	75	-55.9	65.8	3.7	1468	90.4	5.1
16	Gulf Oil	-329	Def	Def	Def	1232	6.6	Def
17	Rohm & Haas	156	-16.6	98.7	9.0	1008	90.7	15.5
18	American Cyanamid	100	-49.5	43.4	5.9	1308	56.5	7.6
19	Stauffer Chemical	285	-7.3	100.0	17.6	1756	100.0	16.2
20	American Hoechst	NA	NA	NA	NA	NA	NA	NA
21	Texaco	-20	Def	Def	Def	953	4.5	Def
22	Ethyl	161	4.5	84.5	11.4	959	86.7	16.8
23	Air Products ^d	189	-4.2	93.7	13.9	1596	73.6	11.8
24	FMC	149	-23.4	81.7	11.3	1084	39.2	13.7
25	Ciba-Geigy	NA	NA	NA	NA	NA	NA	NA

Def = Deficit.

NA = Not available.

^aSales less administrative expense and cost of selling.^bOperating profit as a percentage of chemical sales.^cOperating profit as a percentage of tangible chemical assets.^dFiscal year ended September 30, 1982.

TABLE 9-14. CASH FLOW FOR MAJOR CHEMICAL PRODUCERS, 1970-1982

Source/application of funds	1982		1981		1980		1979		1978	
	10 ⁶ \$	% of total	10 ⁶ \$	% of total	10 ⁶ \$	% of total	10 ⁶ \$	% of total	10 ⁶ \$	% of total
Sources of funds										
Net income	\$2,892	17.9%	\$4,358	18.2%	\$3,981	33.2%	\$3,801	36.3%	\$3,085	33.6%
Depreciation and depletion	5,073	31.5	4,267	17.9	3,818	31.8	3,602	34.4	3,197	34.8
Deferred taxes	694	4.3	1,012	4.2	679	5.7	427	4.1	353	3.8
Other internal sources	2,167	13.4	1,833	7.7	815	6.8	1,093	10.5	930	10.1
Long term debt	3,466	21.5	7,493	31.4	2,079	17.3	1,210	11.6	1,545	16.8
Stock	1,834	11.4	4,931	20.6	630	5.2	322	3.1	84	0.9
Total	16,126	100.0	23,894	100.0	12,002	100.0	10,454	100.0	9,194	100.0
Applications of funds										
Dividends	\$2,003	12.4%	\$1,845	7.7%	\$1,603	13.4%	\$1,474	14.1%	\$1,317	14.3%
Capital expenditures	8,506	52.7	8,344	34.9	7,027	58.5	5,633	53.9	5,080	55.3
Additions to working capital	-1,842	-11.4	3,759	15.7	1,057	8.8	1,075	10.3	863	9.4
Reduction of long-term debt	4,335	26.9	1,483	6.3	1,119	9.3	1,042	10.0	879	9.5
Other applications	3,124	19.4	8,453	35.4	1,196	10.0	1,230	11.7	1,054	11.5
Total	16,126	100.0	23,894	100.0	12,002	100.0	10,454	100.0	9,194	100.0

^aData are totals for 15 major chemical companies.^bCurrent dollars.

TABLE 9-15. DEBT RATIOS FOR THE U.S. CHEMICALS INDUSTRY AND FOR U.S. MANUFACTURING, 1978-1982

Industry group	1982	1981	1980	1979	1978	1977	1976	1975	1974	1973	1972
Industrial chemicals and synthetics											
Long term debt ^a	\$21.0	\$21.4	\$16.8	\$14.8	\$13.6	\$12.3	\$11.8	\$10.2	\$7.8	\$7.2	\$7.6
Stockholders' equity ^a	\$44.1	\$42.5	\$39.8	\$32.3	\$29.3	\$26.3	\$25.0	\$22.8	\$20.5	\$18.7	\$18.5
Debt ratio	32.2%	33.5%	29.6%	31.4%	31.6%	31.9%	32.0%	30.0%	27.6%	27.6%	29.2%
Chemicals and allied products											
Long term debt ^a	\$17.2	\$36.9	\$28.3	\$24.9	\$23.5	\$21.1	\$19.4	\$16.8	\$12.8	\$10.7	\$11.5
Stockholders' equity ^a	\$93.2	\$89.9	\$79.5	\$67.4	\$60.8	\$54.9	\$50.8	\$45.7	\$40.9	\$36.7	\$36.1
Debt ratio	28.5%	29.1%	26.3%	27.0%	27.5%	27.6%	27.6%	26.9%	23.6%	22.6%	24.2%
All manufacturing											
Long term debt ^a	\$292.9	\$266.5	\$236.2	\$204.8	\$182.0	\$167.3	\$153.6	\$145.2	\$130.1	\$112.9	\$110.3
Stockholders' equity ^a	\$782.3	\$762.3	\$699.7	\$624.0	\$560.8	\$511.7	\$475.3	\$435.5	\$408.4	\$368.0	\$353.1
Debt ratio	27.2	25.9	25.2	24.7	24.5	24.6	24.4	25.0	24.2	23.5	25.1

^aCurrent dollars.^bLong-term debt as a percentage of long-term debt plus stockholders' equity.

The change in capital structure from internal financing to debt financing is related to a variety of factors. The industry has high fixed costs because of the large capital costs of plants. Fixed costs do not depend on the rate of production in any given period. When supply and demand conditions are such that plants do not operate at full capacity, these high fixed costs are distributed over lower production volumes, resulting in lower profit margins and returns on stockholders' equity. Profitability and capital utilization generally vary together. Capacity utilization was relatively high in the early 1970s (above 80 percent), fell below 80 percent between 1975 and 1977, and rose again between 1977 and 1980. Since 1980, capacity utilization has been very low, falling to 61 percent in 1982.⁵⁸ Profitability is expected to rebound as demand grows and capacity utilization increases.

9.1.5.2 Trends in the Chemical Industry. This section is a summary of the movements in industry variables. Particular emphasis is given to some of the trends within the various end-use groups identified for the 173 reactor processes chemicals.

9.1.5.2.1 Overall industry trends. The chemicals industry has traditionally been a growing and dynamic industry within the manufacturing sector, usually growing at a faster rate than the economy as a whole because of its generation of new products and rapidly changing technological capability. Long-term growth in the physical output of the industry has averaged 7.5 percent annually since 1960, as compared to 4 percent per year for the manufacturing industries.⁴² The level of this output fluctuates with conditions in the economy as a whole.

Until 1973, prices within the chemical industry demonstrated a steady downward trend. In 1973, the oil supply shocks and subsequent rising feedstock prices initiated increasing prices for most organics. Rising labor costs, combined with lower productivity, have supplemented the price increases.

Profitability in the chemical industry is determined largely by the capacity utilization of chemical plants. This utilization level is determined in the short run by demand factors that depend on the overall activity in the economy. Thus, the profitability of chemicals tends to be higher in periods of economic growth and lower in periods of recession.

A variety of factors may cause changes in the response of the chemical industry to economic fluctuation in the future. Rising costs, foreign trade competition, and a maturing industry have led some analysts to believe that more and more chemical companies will enter into specialty chemical production and leave commodity production.⁵⁹ A reorganization of the industry is expected in which unprofitable plants and operations are closed or go out of business permanently to ensure the competitiveness of the firm as a whole.⁵⁹

9.1.5.2.2 Description of end-use groups. The various end-use groups into which the reactor process chemicals fall have experienced trends similar to those of the whole industry, but have some characteristics peculiar to each group. Some of these characteristics are discussed below.

Basic chemicals are particularly tied to petroleum trends. Many olefin plants are being built with flexibility in feedstock usage to allow for the use of alternative feedstocks as those prices change.

Intermediates differ from other chemicals in that they are often consumed captively by their producers. Therefore, reported production figures for these chemicals based on sales generally underestimate actual production. Total demand for intermediates, both external and internal, depends directly on demand for their derivatives.

Plasticizers are used in the production of flexible polymers, such as PVC, and are tied to the growth of the construction industry and related industries. Pesticides are used primarily in the agricultural sector, so their use is related to agricultural output. Growth in the production of pesticides has traditionally been quite high.

Domestic consumption of aerosol propellants declined when they were implicated in causing adverse upper-atmospheric environmental effects. However, fluorocarbons with refrigerant and polymer end-uses now are expected to experience some growth.

Fuel additives such as tetraethyl lead (TEL) and tetramethyl lead (TML) are controlled by government regulation of gasoline, resulting in a reduction in overall demand. Other fuel additives, such as methyl tertiary-butyl ether (MTBE), have taken up the market traditionally supplied by TEL/TML and have shown substantial growth.

9.1.6 Five-Year Industry Growth Projections

This section projects the number and capacity size of expansion and replacement process units for the period July 1, 1985, through July 1, 1990, for the production of the reactor processes chemicals. As defined in Chapter 5, a process unit is one or more reactors feeding off-gas into a common product recovery train. Process units affected by the regulatory alternatives are built both to meet expanding demand and to replace capacity because of plant retirement. For the purpose of these projections, the number of process units added by 1990 is estimated based on the need for additional capacity due both to outward shifts in demand (expansion capacity) and to plant retirement (replacement capacity).

Technically, expansion capacity may take the form of new grassroots process units or of small process units added at existing production sites. Replacement capacity is defined as capacity built to accommodate retirement of existing capacity because of age or technological change. Replacement capacity generally occurs as onsite reconstructions or as grassroots construction of process units. During the 5-year period beginning July 1, 1985, 56 process units are projected to be built to accommodate growth and plant retirement in the reactor processes segment of the synthetic organic chemical industry. Most of these process units will be built because of the retirement of old process units. Approximately one-third will be built due to increases in demand for chemicals.

As discussed in Chapter 3, the projected process units are assumed to have emission characteristics similar to those in the emissions data profile (EDP). Many of the affected chemicals are currently produced in areas that have Federal or State regulations affecting VOC emissions from SOCM plants. In the projections, it is assumed that affected chemical capacity will be located in states whose State Implementation Plans (SIPs) are similar to those of states in which most of that chemical's current production is located. If strict SIPs apply in those locations, that chemical is assumed to be controlled at the baseline. Therefore, separate projections for SIP and non-SIP process units are not made. Though the EDP does not exclude batch process data from its calculations, the economic analysis assumes there are no batch processes for the 173 large-volume chemicals. The projections cover the area that includes the 50 States, the District of Columbia, and Puerto Rico to the extent available data allow. The following sections describe the methodologies used to arrive at these projections.

9.1.6.1 Projection of Capacity Requirements. For each chemical, the required increase in capacity due to increased demand and plant retirement over the 5-year projection interval is computed as a function of projected 1990 production, estimated 1985 capacity, an estimate of plant retirement, and an assumed projected capacity utilization at existing plants in 1990.

Projections of 1990 production and estimates of 1985 capacity are made in two ways. Chemical-specific projections are made for those chemicals for which data are available. For other chemicals, average growth trends and capacity utilization factors for the general end-use groups identified in Section 9.1.2 are used. The chemical-specific and end-use methodologies for obtaining 1985 capacity and 1990 production projections are detailed below. The data used in projecting 1990 production and potential required capacity for the 173 large-volume chemicals are presented in Table 9-16.

9.1.6.1.1 Chemical-specific growth projection methodology. Of the 173 large-volume chemicals, 110 have growth potential sufficient to project the need for additional plant capacity by 1990. For 73 of the chemicals with potential for growth, complete data are available from a variety of sources on historical domestic consumption, exports, imports, and capacity, along with projections of future consumption, exports, and imports.⁴⁻⁶ These data, along with estimates of 1985 production and capacity, are used to project 1990 production and capacity requirements.

For the most part, 1985 capacity and production are estimated based on data and forecasts from Mannsville Chemical Products Synopsis (MCP) and the Chemical Marketing Reporter (CMR).⁴⁻⁵ For those chemicals for which no estimates are available, 1985 capacity is assumed to be the same as the latest actual or projected capacity figures available, and 1985 production is equal to the latest production figure times a yearly growth rate factor.^{4,5,7,10} When the assumed 1985 capacity is less than estimated production in 1985, 1985 capacity is increased to equal production in 1985 divided by an assumed average capacity utilization rate of 85 percent.⁵⁸

TABLE 9-16. PROJECTED U.S. PRODUCTION, CAPACITY, AND GROWTH RATES
FOR REACTOR PROCESSES CHEMICALS FOR 1985^{4 5 6 7 8 9 10}

Chemical	1985 Produc- tion, Gg	1985 Capa- city, Gg	Annual growth rate, %	Sources ^b
Acetaldehyde	91	272	0	MCP 1/83, CMR 1/11/82
Acetic acid	1503	1905	3	MCP 4/82, CMR 5/9/83
Acetic anhydride	522	653	0	MCP 9/82, CMR 5/16/83
Acetone	1017	1482	2	MCP 3/83, CMR 9/25/80
Acetone cyanohydrin	513	828	3	USITC 1981, EU
Acetylene	166	195	2.5	MCP 9/82
Acrylic acid	229	*	*	USITC
Acrylonitrile	853	1052	3	MCP 4/83
Adipic acid	701	803	0.6	MCP 8/81, CMR 11/24/80
Adiponitrile	187	366	3	TSCA, EU
Alcohols, C-11 or lower, mixed	55	95	2	USITC, EU
Alcohols, C-12 or higher, mixed	352	608	2	USITC, EU
Alcohols, C-12 or higher, unmixed	91	156	2	USITC, EU
Allyl chloride	*	*	2	EU
Amylene	79	137	2	TSCA, EU
Amylenes, mixed	45	78	2	EU
Aniline	372	581	5	MCP 10/82, CMR 2/2/82
Benzene	5860	7761	2.5	MCP 7/82, CMR 1/5/81
Benzenesulfonic acid	48	236	3	TSCA, EU
Benzenesulfonic acid, mono- C ₁₀₋₁₆ alkyl derivatives, sodium salts	45	71	3	EU
Benzyl chloride	59	82	3	MCP 7/78, CMR 8/31/81
Bisphenol A	320	374	10	MCP 1/82, CMR 5/26/80
Bivinyll	1388	2107	3	USITC, SRI 1982, PTS, EU
Brometone	45	69	0	PC
Butadiene and butene fractions	511	*	3	USITC, EU
Butanal	434	717	2	USITC, SRI 1982, EU
Butane	844	2010	3	USITC, EU
Butane, mixed	45	78	2	EU
1,4-Butanediol	164	193	5	MCP 4/81
2-Butoxyethanol	2045	3205	3.7	MCP 12/82, CMR 6/6/81

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(continued)

TABLE 9-16 (continued)

Chemical	1985 Produc- tion, Gg	1985 Capa- city, Gg	Annual growth rate, %	Sources ^b
Butyl acrylate	138	203	2	USITC, EU
n-Butyl acetate	60	77	3	MCP 3/83, CMR 10/26/81
t-Butyl alcohol	463	712	2	TSCA, EU
sec-Butyl alcohol	213	367	2	SRI 1982, EU
n-Butyl alcohol	383	680	3	MCP 12/81, CMR 12/7/81
Butylbenzyl phthalate	48	685	0	TSCA, PC
α + β -Butylene ^c	400	471	3	PTS, SRI 1982, EU
Butylenes, mixed	281	752	3	SRI 1982, USITC, EU
t-Butyl hydroperoxide	45	69	3	EU
2-Butyne-1,4-diol	45	250	2	TSCA, EU
Butyric anhydride	45	78	0	PC, EU
Caprolactam	419	567	0.8	CMR 9/22/80
Carbon disulfide	171	304	1	MCP 3/83, CMR 1/24/83
Carbon tetrachloride	316	494	1	MCP 2/83, CMR 2/21/83
Chloroacetic acid	47	59	2	MCP 12/81, CMR 4/25/83
Chlorobenzene	120	159	3.7	MCP 2/83, CMR 10/6/80
Chloroform	191	379	3.5	MCP 1/83, CMR 1/31/83
p-Chloronitrobenzene	45	73	3	EU
Citric acid	157	186	2.5	MCP 8/81
Cumene	1558	2134	7.6	MCP 4/83, CMR 5/11/81
Cumene hydroperoxide	45	69	3	EU
Cyanuric chloride	45	73	3	EU
Cyclohexane	842	1322	1.5	MCP 6/82
Cyclohexane, oxidized	68	117	2	TSCA, EU
Cyclohexanol	45	998	0	TSCA, PC
Cyclohexanone	340	1089	1.5	MCP 9/82
Cyclohexanone oxime	45	78	0	PC, EU
Cyclohexene	45	78	0	PC, EU
Diacetone alcohol	19	27	7.5	MCP 5/82
1,4-Dichlorobutene	45	250	3	TSCA, EU
3,4-Dichloro-1-butene	45	89	3	EU
Diethanolamine	73	114	3	USITC, EU
Diethylbenzene	45	68	3	EU

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TABLE 9-16 (continued)

Chemical	1985 Produc- tion, Gg	1985 Capa- city, Gg	Annual growth rate, %	Sources ^b
Diethylene glycol	199	318	3	MCP 12/81
Diisodecyl phthalate	100	189	*	USITC, EU
Dimethyldichlorosilane	45	69	3	EU
Dimethylterephthalate	2835	3335	2	USITC
2,4-(and 2,6)-Dinitrotoluene	45	69	3	EU
2,4-Dinitrotoluene	252	381	3	USITC, EU
Dioctyl phthalate	136	386	2.5	MCP 6/82
Dodecene	188	232	2	USITC, SRI 1982, EU
Dodecylbenzene, linear	126	465	1.5	CMR, MCP 1/82
Dodecylbenzene, nonlinear	121	188	1.5	MCP 1/82
Dodecylbenzenesulfonic acid	113	177	1.5	USITC, EU
Dodecylbenzenesulfonic acid, sodium salt	174	272	1.5	USITC, EU
Epichlorohydrin	204	290	3	MCP 1/82
Ethanolamine	221	295	3	MCP 11/82, CMR 5/3/82,
Ethyl acetate	113	133	2.3	MCP 1/81, CMR 1/17/83
Ethyl acrylate	136	199	2	USITC, EU
Ethyl alcohol	566	824	2	MCP 2/82, CMR 5/24/82
Ethylbenzene	4154	4774	3	MCP 11/81, CMR 2/23/81
Ethyl chloride	88	302	-12	MCP 3/83
Ethylene	14067	17736	4.5	MCP 4/83, CMR 4/19/82
Ethylene dibromide	83	142	0	USITC, EU
Ethylene dichloride	5383	8101	4	MCP 6/81, CMR 6/13/83
Ethylene glycol	2050	3205	3.7	MCP 12/82, CMR 6/15/81
Ethylene glycol monoethyl ether	85	130	2.5	USITC, EU
Ethylene glycol monoethyl ether acetate	45	70	0	PC, EU
Ethylene oxide	2404	3402	3.6	MCP 12/82, CMR 6/8/81
2-Ethylhexyl alcohol	177	268	4	MCP 6/82, CMR 3/8/82
(2-Ethylhexyl) amine	45	78	0	PC, EU
6-Ethyl-1,2,3,4-tetrahydro- 9,10-anthracenedione	45	73	3	EU

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TABLE 9-16 (continued)

Chemical	1985 Produc- tion, Gg	1985 Capa- city, Gg	Annual growth rate, %	Sources ^b
Fluorocarbon 113	45	73	4	EU
Formaldehyde	2681	4128	4	MCP 12/81
Freon 11	74	119	4	MCP 8/82
Freon 12	148	239	4	MCP 8/82, CMR 3/7/83
Freon 21	45	73	4	EU
Freon 22	115	185	4	MCP 8/82, CMR 3/7/83
Glycerin	60	70	0.5	MCP 2/82
Heptane	45	80	5	EU
Heptenes, mixed	63	75	2	USITC, SRI, EU
Hexane	182	314	2	USITC, EU
Hexamethylene diamine	*	979	3	TSCA, EU
Hexamethylene diamine adipate	45	89	3	EU, TSCA
Hexamethylene tetraamine	41	68	0	MCP 6/82
Isobutane	519	1237	3	USITC, EU
Isobutyl alcohol	92	109	2	USITC, SRI, EU
Isobutylene	530	624	4.2	PTS, SRI
Isobutyraldehyde	131	177	2	USITC, SRI, EU
Isopentane	2515	988	3	TSCA, EU
Isoprene	241	284	3	USITC, SRI 1982, EU
Isopropyl alcohol	920	1340	1.5	MCP 6/81, CMR 3/2/81
Ketene	45	78	0	PC, EU
Linear alcohols, ethoxylated, mixed	215	406	2	USITC, EU
Linear alcohols, ethoxylated and sulfated, sodium salt, mixed	66	96	3	USITC, EU
Maleic anhydride	147	222	4.5	MCP 9/82, CMR 8/1/83
Methyl alcohol	6622	7790	9	MCP 7/82
Methylamine	112	157	3	CMR 1/18/82
ar-Methylbenzenediamine	45	69	3	EU
Methyl chloride	157	282	0	MCP 4/82, CMR 3/21/83

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(continued)

TABLE 9-16 (continued)

Chemical	1985 Produc- tion, Gg	1985 Capa- city, Gg	Annual growth rate, %	Sources ^b
Methyl chloroform	319	433	3	MCP 11/82, CMR 3/28/83
Methylene chloride	291	458	3	MCP 5/83
Methyl ethyl ketone	243	318	3	MCP 11/82, CMR 8/9/82
Methyl isobutyl ketone	96	113	8	MCP 5/82, CMR 12/15/80
Methyl methacrylate	462	590	4.5	MCP 8/82, CMR 12/14/81
Mesityl oxide	45	70	2	EU
2-Methylpentane	45	78	2	EU
1-Methyl-2-pyrrolidone	45	68	3	EU
Methyl-t-butyl ether (MTBE)	1814	2134	10	MCP 7/82
Naphthene	69	318	3	USITC, SRI 1982, EU
Nitrobenzene	522	760	3.5	MCP 9/80, CMR 8/6/82
Nonyl alcohol	45	86	0	PC
Nonylphenol	70	173	3	MCP 9/82
Nonylphenol, ethoxylated	117	184	*	USITC, EU
Octene	45	86	2	EU
Oil-soluble petroleum sulfonate, calcium salt	119	185	3	USITC, EU
3-Pentenitrile	45	69	0	PC
Pentaerythritol	49	84	1	MCP 1/83, CMR 4/4/83
Pentenes, mixed	80	138	2	USITC, EU
Perchloroethylene	274	411	-2	MCP 5/83, CMR 3/14/83
Phenol	1143	1581	1.8	MCP 3/83, CMR 9/1/80
1-Phenylethyl hydroperoxide	45	69	3	EU
Phenylpropane	45	68	3	EU
Phosgene	884	1040	3.5	MCP 9/80
Phthalic anhydride	393	712	3	MCP 12/82, CMR 7/11/82
Propanal	45	78	2	EU
Propane	3862	9195		USITC, EU
Propyl alcohol	66	100	2	MCP 2/83
Propylene	6600	15714	3.5	MCP 8/82
Propylene glycol	338	398	5.5	MCP 6/81
Propylene oxide	1045	1433	4.5	MCP 6/81, CMR 12/21/81
Sorbitol	99	205	4.6	MCP 7/82, CMR 6/21/81
Styrene	3485	4184	4.3	MCP 10/82, CMR 1/12/81
Terephthalic acid	2373	3011	3.5	MCP 5/83

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TABLE 9-16 (continued)

Chemical	1985 Produc- tion, Gg	1985 Capa- city, Gg	Annual growth rate, %	Sources ^b
Tetraethyl lead/tetramethyl lead	125	170	0	USITC, SRI
Tetrahydrofuran	53	78	2	EU, SRI 1982
Tetra (methyl-ethyl) lead	60	105	0	USITC, EU
Toluene	414	986	5.7	MCP 9/82, EU
Toluene-2,4-diamine	100	239	3	EU, USITC
Toluene-2-4-(and 2,6)-diisocyanate (80/20 mixture)	323	380	2	MCP 4/82, CMR 11/15/82
Trichloroethylene	92	154	-1	MCP 3/83,
Triethanolamine	62	97	3	USITC, EU
Triethylene glycol	57	82	1	MCP 11/81,
Trimethylene	45	60	3	EU
Tripropylene	148	256	2	EU, SRI 1982
Vinyl acetate	953	1089	4.5	MCP 4/83, CMR 5/23/83
Vinyl chloride, monomer	3287	4110	4	MCP 1/83, CMR 6/20/83
Vinylidene chloride	*	*	5.5	EU
Vinyl trichloride	98	151	2	USITC, EU
Xylenes, mixed	3087	7348	2	MCP 1/83
m-Xylene	*	*	3	EU
o-Xylene	502	591	2	MCP 1/83
p-Xylene	1929	2434	4	MCP 1/83

^aGrowth rate for consumption.

^bSource abbreviations refer to the following publications and assumptions:

MCP Mansville Chemical Products Synopsis
 CMR Chemical Marketing Reporter
 SRI SRI Directory of Chemical Producers
 USITC USITC Synthetic Organic Chemicals: U.S. Production and Sales, various years
 TSCA Toxic Substances Control Act Survey
 PTS Predicasts, Inc. PTS U.S. Forecasts Data
 PC Growth rate based on production chain analysis
 EU End-use growth rate average and/or capacity utilization factor used.

^cData for α - and β -butylene are combined. Approximately 25 percent of total production is β -butylene.

*These data are considered proprietary and are used in subsequent calculations.

For 1990 production, projections are made by applying a consumption growth rate to 1985 production:

$$1990 \text{ Production} = (1 + \text{GR})^5 \times 1985 \text{ Production} ,$$

where

$$\text{Production} = (\text{consumption and exports}) - \text{imports}$$

$$\text{GR} = \text{forecast growth rate of consumption.}$$

Specifically, production is considered a function of domestic consumption, exports, and imports, with imports being subtracted from and exports added to domestic consumption figures to account for all production. In extrapolating 1981 and 1982 import and export data to 1990, it is assumed that imports and exports in 1990 will maintain the same percentage relationship to domestic consumption as they did in the year of the most current data. It is also assumed that no changes in inventory levels would occur.

9.1.6.1.2 End-Use projection methodology. Projections cannot be made in the manner described above for a number of chemicals due to a lack of chemical-specific data. These chemicals are arranged into 14 end-use groups as described in Section 9.1.2. It is assumed that chemicals with similar end uses will experience similar growth in domestic production and consumption during the period 1985 through 1990.

For those chemicals for which current production and capacity are available but for which no estimates of future growth rates are found, the average annual growth rate for the end-use group is used to project 1990 production. The end-use growth rates averaged are those expected for the individual chemicals or those inferred from published projections of future production. Table 9-17 shows the average rounded growth rates for each end-use group.

The growth rates for several chemicals are determined using production chain analysis. If the chemicals used to manufacture the chemical of interest and the chemicals made from the chemical of interest show no growth, then that chemical is considered not to be growing.

For a number of chemicals, production information is available, but not capacity estimates. In these cases, the capacity for the chemical is estimated using production and a capacity utilization factor derived for each end-use group. The capacity utilization factor is an average of the ratios of production to capacity for those chemicals with complete data in each end-use group. Table 9-17 also presents the average capacity utilization figures for each end-use group.

For several chemicals, no data on production or capacity are available. In these cases, a 1985 production of 45.4 Gg, the minimum production level

TABLE 9-17. END-USE GROUP AVERAGE GROWTH RATES, RATIOS OF RETIRED CAPACITY TO 1990 PRODUCTION, AND CAPACITY UTILIZATION FOR REACTOR PROCESSES CHEMICALS IN THE 1980s

Group	Average end-use annual growth rates, %	Average ratio of retired capacity to 1990 production	Average end-use capacity utilization, %
Basic chemicals	3	0.24	42
General aromatics	3	0.26	67
General nonaromatics	2	0.45	58
Synthetic elastomers	3	0.35	51
Plastics and fibers	3	0.29	66
Plasticizers	2	0.34	53
Pesticides	3 ^a	0.28 ^b	62 ^c
Dyes	3 ^a	0.28 ^b	62 ^c
Solvents	2	0.39	65
Detergents and surfactants	3	0.12	64
Fuel additives	5	0.28 ^b	57
Aerosol propellants and refrigerants	4	0.28 ^b	62 ^c
Coatings	2	0.34	68
Miscellaneous end-use	3	0.20	76

Note: Figures are rounded.

^aThe growth rates for the groups pesticides and dyes are the average for the entire group of 173 chemicals.

^bThe figure is the overall group average ratio of retired capacity to 1990 production figures.

^cThe capacity utilization figures for pesticides, dyes, and aerosol propellants and refrigerants are the overall group average. Data are insufficient to determine end-use averages for these groups.

required for inclusion in the study, is used. This estimate of 1985 production is used with the end-use growth rate to estimate 1990 production. The minimum production figure is also used with the end-use capacity utilization figure to estimate 1985 capacity.

No production information is available for allyl chloride, sec-butyl alcohol, tetrahydrofuran, and tripropylene. However, capacity information is used, along with the capacity utilization average for the respective end-use groups, to estimate production in 1985. The end-use growth rate is then used to determine growth over the 1985 to 1990 period.

In the case of a few chemicals, estimated 1985 production is slightly larger than existing capacity figures that are used to approximate 1985 capacity. This is due to the assumption of constant capacity and constant export and import proportions. In these cases, 1985 production is divided by the historical capacity utilization rate of 85 percent⁵⁸ to get the 1985 capacity figure.

9.1.6.1.3 Estimation of Retired Capacity. A 20-year lifetime for chemical plants is used for the purposes of this analysis. With this assumption in plant lifetime, the amount of capacity added over the period 1965 to 1970 is roughly the amount of capacity that might be retired during the 1985 to 1990 time period. Data on 1965 and 1970 capacity for 64 of the subject chemicals are available in Mannsville Chemical Products Synopsis⁶⁰ and in Chemical Engineering Construction Alerts.⁶⁰⁻⁶⁵ The additions to production capacity made between 1965 and 1970 in the form of modifications, reconstructions, or grassroots process units are used as an estimate of the amount of capacity that came online during the period.

For those chemicals without chemical-specific information, the amount of retired capacity is estimated by using the average ratio of retired capacity to the production projection for 1990 for the chemicals in its end-use group with data. This average ratio yields a value that is more realistic than the average retired capacity values for the end-use groups, which are larger than the total 1990 production estimates for some of the chemicals. Table 9-17 presents the average ratio of retired capacity to 1990 production for those chemicals with chemical-specific information for each end-use group. Retired capacity for those chemicals without chemical-specific information is thus estimated as its end-use group average ratio x 1990 production.

9.1.6.1.4 Calculation of additional capacity requirements in 1990. The projection technique described below yields the production capacity needed in 1990 to meet the projected growth in consumption for each chemical between 1985 and 1990. Though the methodology actually compares projected 1990 consumption and 1990 available capacity, it estimates the total amount of production capacity that will be added at various times throughout the 5-year period, 1985 to 1990.

The integral element of this methodology is an assumption that defines when additional process units will be constructed throughout the 5-year period. Specifically, based on industry analysis, it is assumed that the industry will not operate its existing capacity at a utilization rate greater than 85 percent.⁵⁸ Therefore, whenever production demand from growth in consumption increases to 85 percent of the capacity available at that time, the industry will decide to construct additional process units.

In the projection methodology, the projected 1990 consumption is compared to 85 percent of the available 1990 capacity to determine if additional process units are needed. Though performed on projected fifth-year values, this calculation gives a reasonable estimate of the capacity that should be added throughout the first 5 years of the standard by employing the construction decision factor of 85 percent maximum capacity utilization.

The actual calculation first subtracts the estimate of capacity retired between 1985 and 1990 from the amount of capacity existing in 1985 to determine the capacity available in 1990. If projected consumption is greater than 85 percent of the capacity available in 1990, then additional production capacity is needed. The minimum amount of capacity that must be added to maintain an industry capacity utilization rate of no more than 85 percent is equal to 1990 consumption divided by 0.85-- total capacity needed--minus the amount of available capacity.

An example demonstrates more clearly the required capacity projection methodology used in this analysis. Acrylonitrile has a projected 1990 production of 981 Gg/yr based on a growth rate in consumption of 3 percent per year. Capacity in 1985 is estimated to be 1,052 Gg/yr, and 279 Gg are estimated to be retired. Thus, 1990 production is greater than 85 percent of capacity available in 1990:

$$>(0.85)(1,052 - 279), 981 > 657.$$

Therefore, the capacity required to accommodate expanded acrylonitrile demand in 1990 is estimated to be 381 Gg/yr:

$$\frac{981}{.85} - (1,052 - 279) = 381 \text{ Gg.}$$

9.1.6.2 Process Unit Projections. A total of 110 of the 173 chemicals will require expansion or replacement capacity during the 1985 to 1990 period (see Table 9-18). As shown in the table, 22 of the 110 chemicals have vent streams that are combusted at baseline based on information in the EDP and, thus, would not require additional controls under any regulatory alternatives considered.⁶⁶ An additional 62 have no vent streams at baseline, so these also would not be significantly affected by the NSPS.⁶⁸ The remaining 26 chemicals that will require additional capacity have vent streams that are not combusted at baseline. Projections of the number of process units needed to accommodate the total amount of additional capacity are made for these chemicals using a single process unit size for each chemical--the median process unit size.

TABLE 9-18. U.S. CONSUMPTION AND CAPACITY PROJECTIONS AND REQUIRED CAPACITY FOR
110 REACTOR PROCESSES CHEMICALS IN 1990 (Gg/yr)

Chemical name	(1) Estimated capacity in 1985	(2) Capacity to be retired (1985-1990)	(3) Capacity available in 1990 (1-2)	(4) Projected consumption in 1990	(5) Additional capacity required to accom- odate consumption in 1990 at 85 percent utilization (4/0.85-3)	Process vent/ baseline combustion
Acetic acid	1905.1	544.3	1360.8	1745.5	692.7	yes/yes
Acetone	1481.5	410.5	1071.0	1152.6	293.3	no/--
Acetylene	165.6	0.0	165.6	190.6	58.7	no/--
Acrylonitrile	1052.4	279.0	773.4	981.1	380.9	no/--
Adipic acid	802.8	215.5	587.3	719.1	258.7	yes/no
Alcohols C-11, or lower mixed	94.6	20.0	66.6	62.0	6.3	no/--
Alcohols C-12, or higher, mixed	607.7	171.7	436.0	379.9	10.9	no/--
Alcohols C-12 or higher, unmixed	156.4	48.5	107.9	107.3	18.4	no/--
Allyl chloride	289.9	86.4	212.5	191.1	12.3	no/--
Anylene	136.9	39.7	97.2	87.9	6.3	no/--
Anylenes mixed	78.2	22.6	55.6	50.0	3.2	no/--
Aniline	580.6	65.7	514.9	474.4	43.3	no/--
Benzene	7761.1	1625.5	6135.6	6682.6	1726.3	no/--

(continued)

TABLE 9-18 (continued)

Chemical name	(1) Estimated capacity in 1985	(2) Capacity to be retired (1985-1990)	(3) Capacity available in 1990 (1-2)	(4) Projected consumption in 1990	(5) Additional capacity ^a required to accom- odate consumption in 1990 at 85 percent utilization: (4/0.85-3)	Process vent/ baseline combustion
Benzyl chloride	81.6	18.1	63.5	68.7	17.3	yes/no
Bisphenol A	374.2	54.4	319.8	504.9	274.2	no/--
BivinyI	2107.0	607.4	1499.6	1752.5	562.2	no/--
Butanal	716.7	164.6	552.1	477.5	9.7	yes/yes
Butanes mixed	78.2	22.6	55.6	50.0	3.2	no/--
1,4-Butanediol	195.5	70.4	105.1	200.0	130.2	yes/yes
2-Butoxyethanol	3204.7	419.6	2785.1	2496.3	151.7	yes/yes
Butyl acrylate	173.4	40.1	133.3	117.9	5.4	yes/no
n-Butyl acetate	77.1	0.0	77.1	71.0	6.5	yes/no
t-Butyl alcohol	711.8	185.8	526.0	481.2	40.1	yes/no
sec-Butyl alcohol	367.4	166.2	261.2	235.0	15.3	yes/yes
a,b-Butylene	258.6	60.7	197.9	216.8	57.2	no/--
t-Butyl hydroperoxide	68.7	15.4	53.3	52.3	8.2	yes/no
Caprolactam	567.0	77.1	489.9	438.9	26.5	no/--

(continued)

TABLE 9-10 (continued)

Chemical name	(1) Estimated capacity in 1985	(2) Capacity to be retired (1985-1990)	(3) Capacity available in 1990 (1-2)	(4) Projected consumption in 1990	(5) Additional capacity ^a required to accom- odate consumption in 1990 at 85 percent utilization ^b (4/0.85-3)	Process baseline combustion
Carbon tetrachloride	494.4	158.8	335.6	367.4	96.6	no/--
Chlorobenzene	158.8	0.0	158.8	143.5	10.0	yes/no
p-Chloronitrobenzene	73.2	14.7	58.5	52.3	3.0	yes/no
Citric acid	186.0	36.6	149.4	180.4	62.9	no/--
Cumene	2134.2	689.5	1444.7	1854.7	737.3	no/--
Cumene hydroperoxide	68.7	15.4	53.3	52.3	8.2	no/--
Cyanuric chloride	73.2	14.7	58.5	52.3	3.0	yes/no
Cyclohexane oxidized	117.3	33.9	83.4	75.0	4.8	no/--
Diacetone alcohol	27.2	11.7	15.5	25.8	14.9	yes/no
Diethylbenzene	67.6	13.4	54.2	52.3	7.2	yes/no
Diethylene glycol	317.5	104.3	213.2	236.4	64.9	no/--
Dimethyldichlorosilane	68.7	15.4	53.3	52.3	8.2	no/--
Dimethylterephthalate	3375.7	1146.9	2228.8	3326.6	1684.9	no/--
2,4-(and 2,6)- Dinitrotoluene	68.7	15.4	53.3	52.3	8.2	yes/no
2,4-Dinitrotoluene	381.4	88.7	292.7	302.3	62.9	yes/no

(continued)

TABLE 9-18 (continued)

Chemical name	(1) Estimated capacity in 1985	(2) Capacity to be retired (1985-1990)	(3) Capacity available in 1990 (1-2)	(4) Projected consumption in 1990	(5) Additional capacity ^a required to accommo- date consumption in 1990 at 85 percent utilizing (4/0.85-3)	Process vent/ baseline combustion
Dodecene	293.9	141.9	152.0	313.9	217.2	no/--
Epichlorohydrin	290.3	22.7	267.6	243.4	18.8	yes/yes
Ethanolamine	294.8	22.7	272.1	257.0	30.2	no/--
Ethyl acetate	122.5	20.4	102.1	126.7	47.0	yes/no
Ethyl acrylate	199.4	56.6	142.8	166.6	53.1	yes/no
Ethyl alcohol	823.7	337.0	486.7	624.1	247.6	no/--
Ethylbenzene	4774.1	1421.7	3352.4	4843.1	2345.3	yes/no
Ethylene	17735.8	4263.8	13472.0	17529.4	7150.9	no/--
Ethylene dichloride	8101.3	2492.5	5608.8	7397.9	3094.6	yes/yes
Ethylene glycol	3204.7	406.0	2798.7	2551.4	202.9	no/--
Ethylene glycol monoethyl ether	130.5	36.8	93.7	95.3	18.4	yes/yes
Ethylene oxide	3402.0	811.9	2590.1	2661.7	541.3	yes/no
2-Ethylhexyl alcohol	267.6	122.9	144.7	224.1	118.9	no/--
6-Ethyl-1,2,3,4- tetrahydro-9,10 anthracenedione	73.2	14.7	58.5	52.3	3.0	yes/yes

(continued)

TABLE 9-18 (continued)

Chemical name	(1) Estimated capacity in 1985	(2) Capacity to be retired (1985-1990)	(3) Capacity available in 1990 (1-2)	(4) Projected consumption in 1990	(5) Additional capacity ^a required to accommo- date consumption in 1990 at 85 percent utilization (4/0.85-3)	Process vent/ baseline combustion
Fluorocarbon 113	73.2	15.3	57.9	54.7	6.5	no/--
Formaldehyde	4127.8	832.4	3295.4	3167.3	430.8	no/--
Freon 11	119.3	25.2	94.1	90.1	12.0	no/--
Freon 12	239.2	50.5	188.7	180.2	23.2	no/--
Freon 21	73.2	15.3	57.9	54.7	6.5	no/--
Freon 22	185.1	39.0	146.1	139.2	17.6	no/--
Glycerin	70.3	49.9	20.4	61.5	52.0	no/--
Heptane	79.6	16.0	63.6	57.2	3.7	no/--
Heptenes mixed	109.5	31.8	77.7	70.3	5.0	no/--
Hexane	313.6	90.8	222.8	200.8	13.4	no/--
Isobutyl alcohol	108.9	38.6	70.3	99.9	47.3	yes/yes
Isobutylene	335.7	86.9	248.8	295.9	99.3	no/--
Isobutyraldehyde	176.9	50.1	126.8	145.3	44.1	yes/yes
Isopentane	2514.8	703.0	1811.8	2890.1	1588.4	no/--
Isoprene	286.7	96.2	190.5	277.5	136.0	yes/yes

(continued)

TABLE 9-18 (continued)

Chemical name	(1) Estimated capacity in 1985	(2) Capacity to be retired (1985-1990)	(3) Capacity available in 1990 (1-2)	(4) Projected consumption in 1990	(5) Additional capacity ^a required to accom- modate consumption in 1990 at 85 percent utilization ^b (4/0.85-3)	Process vent/ baseline combustion
Isopropyl alcohol	1340.4	258.6	1081.8	987.6	80.0	yes/no
Maleic anhydride	222.3	33.1	189.2	183.9	27.2	no/--
Mesityl oxide	69.8	19.3	50.5	50.0	8.3	yes/yes
Methyl alcohol	7883.6	5220.3	2663.3	11548.8	10923.5	yes/yes
Methylamine	157.4	58.5	90.9	129.4	53.4	no/--
ar-Methylbenzenedia- mine	68.7	15.4	53.3	52.6	8.2	yes/yes
Methyl chloride	282.1	99.8	182.3	161.5	7.6	yes/yes
Methyl chloroform	433.2	136.1	297.1	333.6	95.3	no/--
Methylene chloride	458.1	113.4	344.7	299.5	7.6	no/--
Methyl ethyl ketone	317.5	40.8	276.7	275.7	47.6	no/--
Methyl isobutyl ketone	114.3	27.2	87.1	147.5	86.4	yes/yes
Methyl methacrylate	589.6	199.6	390.0	589.7	303.7	yes/no
1-methyl-2-pyrrolidone	67.7	13.4	54.3	52.6	7.2	no/--
Methyl t-butyl ether (MTBE)	2160.0	978.0	1182.0	3492.7	2927.0	no/--

(continued)

TABLE 9-1B (continued)

Chemical name	(1) Estimated capacity in 1985	(2) Capacity to be retired (1985-1990)	(3) Capacity available in 1990 (1-2)	(4) Projected consumption in 1990	(5) Additional capacity ^a required to accom- odate consumption in 1990 at 85 percent utilization (4/0.85-3)	Process vent/ baseline combustion
Nitrobenzene	759.8	172.4	587.4	600.5	119.0	yes/no
Pentanes mixed	137.6	40.0	97.6	88.4	6.3	no/--
Perchloroethylene	410.5	147.4	263.1	244.9	25.1	no/--
Phenol	1580.8	178.7	1402.1	1363.6	202.1	no/--
1-Phenylethyl hydro- peroxide	68.7	15.4	53.3	52.3	8.2	yes/no
Phenylpropane	67.6	13.4	54.2	52.3	7.2	yes/no
Phosgene	1052.4	158.8	993.6	1049.8	341.5	no/--
Propanal	78.2	22.6	55.6	50.0	3.2	yes/yes
Propyl alcohol	99.8	22.7	77.1	76.3	12.7	yes/yes
Propylene glycol	394.6	97.5	297.1	412.5	188.2	no/--
Propylene oxide	1433.4	421.9	1011.5	1389.3	623.0	yes/no
Styrene	4183.6	771.1	3412.5	4081.5	1452.3	yes/yes
Terephthalic acid	3011.9	657.7	2354.2	3061.0	1247.0	no/--
Tetrahydrofuran	77.6	22.7	54.9	58.8	14.3	yes/yes

(continued)

TABLE 9-18 (Continued)

Chemical name	(1) Estimated capacity in 1985	(2) Capacity to be retired (1985-1990)	(3) Capacity available in 1990 (1-2)	(4) Projected consumption in 1990	(5) Additional capacity ^a required to accommo- date consumption in 1990 at 85 percent utilization ^b (4/0.85-3)	Process vent/ baseline consumption
Toluene-2,4-(and 2,6)- diisocyanate (80/20 mixture)	384.7	86.2	298.5	343.8	106.0	na/--
Triethylene glycol	81.7	17.7	64.0	60.0	6.6	na/--
Trimethylene	59.6	10.6	49.0	52.3	12.5	yes/no
Tripropylene	256.3	74.0	182.3	163.8	10.4	na/--
Vinyl acetate	1088.6	410.5	478.1	1208.7	743.9	yes/no
Vinyl chloride	4109.6	916.3	3193.3	4166.0	1707.8	na/--
Vinylidene chloride	180.1	43.1	137.0	146.9	35.9	yes/yes
Vinyl trichloride	150.7	44.7	106.0	115.7	30.0	yes/no
m-Xylene	79.4	22.9	56.5	78.0	35.3	na/--
o-Xylene	597.4	191.7	405.7	652.8	362.3	na/--
p-Xylene	2433.6	736.2	1697.4	2507.8	1253.0	na/--

^aAmounts of required capacity do not reflect the fact that some chemicals are always produced as a coproduct or byproduct of some principal product. A list of these chemicals produced by reactor processes is given in Table 9-19. For those coproduct chemicals it is likely that the required capacity in 1990 will more closely approximate the required capacity of the principal product than the required capacity shown above.

^bThe calculation of required capacity is 1990 production divided by 0.85, which is the total amount of capacity needed in 1990, minus the amount of capacity available in 1990.

NOTE: Some of the 1990 production and 1985 capacity values of this table do not match the initial or corresponding values of Table 9-14. These disparities are due to last minute revisions in the data and sources used to compile Table 9-14. Reanalysis with the revised data shows little net change in economic impacts and emission reductions under the regulatory alternatives.

A single process unit size is selected for the economic and regulatory analyses in Section 9.2 because it is straightforward and appropriate to the level of detail in process unit cost, and because capacity and production data are available from the data base.

By projecting single-sized process unit(s) to accommodate all required capacity in 1990, it is possible and even likely that more capacity is projected to come on line than would strictly be required based on the capacity utilization rate of 85 percent.

Table 9-19 shows the median-sized facility, required capacity, and final capacity utilization after the process units are added for the 26 chemicals that require additional capacity in 1990, are uncombusted at baseline, and have vent streams. None of the capacity utilization rates falls below a level historically unobserved, though a few chemicals would have a rate lower than 70 percent if the median-sized facilities were added. Thus, the current median plant sizes may overestimate the actual process units that will be built in 1990, since capacity utilization would be higher if smaller process units were added.

While the projections are as accurate as data permit, changes in the general state of the economy, technological advances, development of competitive substitutes, discovery of new product uses, and changes in the stability of markets may affect actual industry growth. These projections reflect the most probable scenario and are the best possible given the data available.

Even if subsequent events prove the projections wrong, they remain valid for their intended purpose: as a guide in exploring the future costs and other impacts of the potential NSPS. Reasonable variations in the projection of process units would have no effect on the need for, and selection of, a standard.

9.2 ECONOMIC IMPACT

This section examines the economic impacts of the reactor processes NSPS on the SOCMCI industry in the first 5 years of implementation. Section 9.2.1 reviews the control costs associated with different regulatory alternatives (cost/effectiveness cutoffs). For each regulatory alternative, the analysis presents estimates of the capital costs required for control equipment, annual operating cost, and the fifth-year (1990) annualized cost of control. Because these control costs are assumed to be passed on to consumers, Section 9.2.2 estimates chemical price increases of the subject SOCMCI chemicals under two sets of cost assumptions--reasonable worst-case (RWC) control costs and more likely case (MLC) control costs. In Section 9.2.3, the MLC costs are used as a basis for discussing other economic impacts, including adjustments in the rate of SOCMCI chemical production, and distributive impacts from SOCMCI chemical consumers to chemical producers.

TABLE 9-19. PROJECTED REQUIRED CAPACITY, TYPICAL PLANT SIZE,
NUMBER OF PROCESS UNITS, AND CAPACITY UTILIZATION FOR
26 REACTOR PROCESSES CHEMICALS IN 1990

Chemical name	Total required capacity to achieve utilization of 85%, Gg	Capacity of a typical process unit, ^a Gg	Number of typical process units built in 1990	Projected final utilization of total capacity, 1990, ^b %
Adipic acid	258.7	236	2	67.9
Benzyl chloride	17.3	36	1	69.0
Butyl acrylate	5.4	35 ^c	1	70.1
n-Butyl acetate	6.5	23	1	70.9
t-Butyl alcohol	40.0	5	8	85.0
t-Butyl hydroper- oxide	8.2	11 ^c	1	81.3
Chlorobenzene	10.0	68	1	63.3
p-Chloronitroben- zene	3.0	18 ^d	1	68.4
Cyanuric chloride	3.0	18 ^d	1	68.4
Diacetone alcohol	14.9	7 ^c	3	70.7
Diethylbenzene	7.2	18 ^d	1	72.4
2,4-(and 2,6)- Dinitrotoluene	8.2	17 ^c	1	74.4
2,4-Dinitrotoluene	62.9	80 ^c	1	81.1
Ethyl acetate	47.0	15	4	78.2
Ethyl acrylate	53.1	40 ^c	2	74.8
Ethylbenzene	2345.3	318	8	82.1
Ethylene oxide	541.3	204	3	83.1
Isopropyl alcohol	80.0	206	1	76.7

(continued)

TABLE 9-19 (continued)

Chemical name	Total required capacity to achieve utilization of 85%, Gg	Capacity of a typical process unit, ^a Gg	Number of typical process units built in 1990	Projected final utilization of total capacity, 1990, %
Methyl methacrylate	303.7	95	4	76.5
Nitrobenzene	119.0	153	1	81.1
1-Phenylethyl hydroperoxide	8.2	18 ^d	1	72.6
Phenylpropane	7.2	18 ^d	1	73.7
Propylene oxide	623.0	322	2	84.0
Trimethylene	12.5	18 ^d	1	78.1
Vinyl acetate	743.9	193	4	83.4
Vinyl trichloride	30.0	45	1	76.6

^aTypical process unit size is most often the median process unit size as shown in Table 9-10.

^bFinal capacity utilization is calculated as the percentage of total industry capacity, after the new process units of the typical size are added, that is used to produce each chemical to meet projected 1990 consumption. If the total capacity requirements shown in column 1 were made into process units of their respective size, all numbers in the capacity utilization column would be 85 percent. Since we add process units of a typical size to cover the capacity requirements, more capacity is added than is needed sometimes and capacity utilization falls:

^cWhen specific process unit sizes are not available, the average process unit size is used for these chemicals.

^dWhen no median or average data are available for a chemical, a simple default value of 18 Gg is used. 18 Gg is the overall median value of all process-specific median values of observed process unit sizes.

9.2.1 Control Cost Impacts

The regulatory alternatives, introduced in Section 8.2, are based on a series of successively more stringent cost/effectiveness cutoffs known as total resource effectiveness (TRE) values. These values measure the dollar cost per megagram (Mg) of VOC controlled. When a process unit's calculated TRE value is less than a particular cutoff prescribed by one of the regulatory alternatives, that unit will have to control 98 percent of all VOC emissions. A TRE value is calculated for all facilities that will come on line between 1985 and 1990, as a function of each facility's vent stream characteristics. Thus, as the TRE cutoffs are raised, more facilities will have a cost/effectiveness less than the TRE cutoff and will be required to control emissions.

The control cost of a regulatory alternative is the cost of purchasing, installing, and operating the required control devices over the life of the plant equipment. The control costs presented here are based on the regulatory analysis of Section 8.2. In that analysis, the chemical-specific projections from Section 9.1 of affected facility capacities coming on line between 1985 and 1990 are matched with the process and vent stream data of the emission data profile (EDP). Cost algorithms are then applied to each facility characterization to estimate facility-specific control costs. The cost/effectiveness (TRE) of each facility is computed by dividing cost by emission reduction to determine at what regulatory alternative cutoff level that facility would be required to install the control equipment. The estimated control costs for all affected facilities required to meet the standard under each regulatory alternative are then summed to obtain the aggregate control cost for that alternative.

Table 9-20 presents estimates of the nationwide control cost for each regulatory alternative through 1990. All costs are expressed in 1982 dollars. As described in Section 8.1, the control costs are computed with an assumed 10-year equipment life and a 10-percent real rate of discount. Table 9-20 expresses these costs in a variety of ways to provide perspective on their composition and magnitude. The table gives the total capital costs and annualized capital costs associated with control for each of the regulatory alternatives. The operating costs and the fifth-year annualized control cost are also presented.

Cost minimizing firms will have an incentive, of course, to reduce the cost of complying with the regulation. The TRE cutoff offers several ways of doing this. First, the firm might design additional product recovery into the facility to reduce the amount of VOC emitted and raise the TRE to an amount above the cutoff. Second, it might be able to build multiple facilities of reduced size, thereby raising the TRE on individual facilities. Third, the firm might modify reactor process design or operating conditions, by changing feedstocks, temperature, pressure or other conditions to increase control costs, reduce emissions, and therefore raise the TRE. The method or combination of methods chosen would have a cost less than the control cost that otherwise would be incurred under the regulation.

TABLE 9-20. CONTROL COSTS FOR REGULATORY ALTERNATIVES IN 1982 DOLLARS

Regulatory Alternative	Cost- Effectiveness Cutoff (\$/Mg VOC)	Total Capital Costs (Million \$)	Annualized Capital Costs (Million \$)	Annual Operating Costs (Million \$)	Fifth Year Annualized Control Costs (Million \$)
I ^a	0	0	0	0	0
II	1,200	.27	.036	.11	.15
III	2,500	5.9	.96	2.7	3.7
IV	5,000	6.1	.98	2.9	3.9
V	20,000	7.3	1.2	3.5	4.7
VI	50,000	12.1	1.9	4.8	6.7
VII	200,000	13.7	2.2	5.2	7.4
VIII	500,000	15.4	2.4	5.8	8.2
IX	>500,000	17.3	2.7	6.6	9.3

^aBaseline, or conditions that would exist in the absence of the standards.

Other methods may also be available to reduce control costs. Specifically, some firms may be able to route the reactor vent stream to an already existing boiler, flare, process heater, or incinerator. This will meet the requirements of the standards with little additional investment and operating expense, and will also have potential for energy savings. The producer may also have alternatives to building new capacity to produce more of the regulated large-volume chemical. The producer may build capacity for small-volume chemicals that are good substitutes, or switch to a large-volume reactor chemical that has a lean vent stream, or find means to produce the chemical using a nonreactor process. If these options exist and are pursued successfully, the control costs of each regulatory alternative might be considerably less than those estimated in Table 9-20. While the economic impacts for the proposed standard are somewhat overstated, the degree of overstatement cannot be quantified.

If a firm is able to avoid compliance with the regulation by any of the methods described above, it still must comply with the monitoring and record-keeping requirements of the regulation. It must continually monitor and prove that its TRE value is above the cutoff, or that 98 percent control is being maintained.

9.2.2 Price Impacts

The purpose of the price analysis is to determine if any of the affected chemicals might experience a major price increase as a result of NSPS. Price impacts are primary indicators of impacts on profits, quantity supplied, employment levels, industry growth, and other economic variables. However, only when these price impacts are of a substantial magnitude should a full-scale analysis be performed to determine the impacts on these other variables.

The primary tool in the price analysis is a computer model that computes the percent price increase for each of the chemicals from the TRE cost of control. A computer model is necessary because the number of chemicals in the subject group (173) is large and because some of the affected chemicals are inputs in the production of other affected chemicals. The model incorporates the process routes for each of the chemicals and can trace control costs through the series of chemicals that are input along a process route. Thus, the model can determine the resulting price impact of the regulation on a final chemical in a process chain and can be modified to analyze price impacts under different sets of assumptions. Section 9.2.2.1 summarizes the assumptions and data used in the analysis, including the prices, plant capacities, and control costs used, and describes the methodology employed in the model. Section 9.2.2.2 provides a discussion of the model results under reasonable worst-case (RWC) assumptions. Section 9.2.2.3 summarizes the assumptions and results of a more likely case (MLC) analysis.

9.2.2.1 Price Analysis Assumptions.

9.2.2.1.1 General assumptions. A number of criteria might be used to identify chemicals that would show significant price increases owing to the

standard. For the purposes of this analysis, if the RWC annualized costs of control for a chemical result in a price increase greater than 5 percent, that chemical is thought to have a significant price impact and is examined further for economic impacts. The 5-percent level is used because it seems a reasonable criterion, especially given the tendency to overstate costs when the worst-case assumptions are used.

The specific input data used in the model are presented in Appendix H, along with other model documentation. The 1982 prices are from Table 9-1, and the capacities for the RWC are the small capacities shown in Table 9-10. The current median process unit size, used to represent the size of process units to be built in 1990 for each chemical and shown in Table 9-19, is used for the MLC.⁴¹ The costs are based on the vent stream characteristics in the EDP scaled to the particular capacities of each case as discussed in Appendix H.

For some chemicals, price and/or capacity data are not readily available. For these chemicals, some of which are not sold widely and thus have no market price, a default price of \$0.46/kg is used. This figure is an average price for SOCOMI chemicals weighted by 1978 production and updated to 1982 dollars.⁶⁷ For those chemicals for which no current plant capacity data are available, a value of 23 Gg is assumed. This figure is the median of the smallest existing plant sizes for the chemicals for which plant capacity data are available. The assumption of small plant size is conservative--i.e., it leads to projections of price increases that are on the high side.

For the purposes of the price impact analysis, perfect competition in a constant-cost industry is assumed. This means that the unit costs incurred by the affected firms are passed through completely to the consumer. This assumption is consistent with the discussion in Section 9.1, which indicates that the affected chemicals in this analysis are largely commodity chemicals produced in competitive markets by firms that are price-takers.

9.2.2.1.2 Model description. The price impact model incorporates the capacity and price data to estimate the effects of the regulation on the individual chemicals in the industry. Firms can incur costs not only from their own direct costs of control but also from the control costs passed through by suppliers of the input chemicals they use. As described in Section 9.1, chemicals are produced in a series of processing steps from basic to intermediate to end-product chemicals. Control costs at each stage affected by the standard may be passed on (or "rolled through") so that costs add up for chemicals produced from other affected chemicals.

The analysis takes into account potential rolled-through control costs by charging control costs for input chemicals to derivatives in proportion to the amounts used in the production of the derivatives. For example, if 1 kg of chemical C is produced from 0.5 kg of chemical A and 0.75 kg of chemical B (with 0.25 kg becoming by-products), one-half of the control costs (per kilogram) for chemical A and three-fourths of the control costs (per kilogram)

for chemical B are added to the direct cost impact for chemical C. This rolled-through cost methodology helps to ensure that the price increases resulting from control costs are conservative in magnitude. Under no circumstances can rolled-through costs be negative due to possible recovery credits. A more detailed description of the model is contained in Appendix H.

9.2.2.2 Reasonable Worst-Case Scenario. While employing reasonable logic, the reasonable worst-case (RWC) scenario posits some extreme conditions that tend to greatly exaggerate projected price increases. The assumptions incorporated in the RWC are described below.

The costs used for the analysis are worst-case costs in that they are estimates of the costs of control scaled to the smallest capacity plant producing a chemical. If no chemical-specific data on plant capacity are available, the costs of control are scaled to the smallest plant of the chemicals produced by the same unit process.

Costs of control are developed based on vent stream information (flowrates, VOC emission rates, and heat contents) contained in the emission data profile (EDP) described in Appendix C. Flowrates (scfm) and VOC emission rates (lb/h) are normalized for each plant in the EDP by dividing these rates for each plant by the plant production capacity (10^6 lb/yr) associated with these rates. Heat content is not normalized because the heat content is based on a unit volume of vent stream. In determining VOC control costs for the RWC, vent stream characteristics were scaled to the smallest plant capacities by multiplying the normalized emission rates from the EDP by the smallest capacities shown in Table 9-10.

Because data are not available for all the chemicals included in the screening analysis, three procedures are used to choose representative emission factors from the EDP for all the chemicals included in the screening analysis⁶⁸ are: (1) the chemical specific method; (2) the chemical process method; and (3) the median method.

As its name implies, the chemical-specific method uses vent stream information from actual plants in the EDP producing a particular chemical. For example, in the case of hexamethylene diamine, data are available from three plants in the EDP. Therefore, chemical-specific data from the EDP can be used to estimate the vent stream characteristics of the hexamethylene diamine plant included in the screening. For many chemicals, vent stream characteristics are available only for one plant in the EDP. For these chemicals, the one EDP plant's data are used in the screening. If data are available from two plants in the EDP producing a particular chemical, average vent stream characteristics for these two are used in the screening. In cases where vent stream information is available from three or more plants, median values are used in the screening.

The chemical process method is used when the chemical process associated with the production of a chemical is known, but chemical specific information

is not available in the EDP. For example, chloroacetic acid is a chemical for which chemical-specific information is not available. All of the chemical-specific information for chemicals produced by the same process is used to obtain representative vent stream characteristics for chemicals using that process. These representative vent stream characteristics are then applied to chemicals in the screening where chemical-specific data are absent in the EDP. As with the chemical specific method, in cases where process specific data are available from only one plant in the EDP, these data are used in the screening for all chemicals using that process. Where data from two plants are available, the average of those vent stream characteristics is used. Finally, in cases where information from three or more plants is available, median values are used.

The median method is used in cases where no information is available for a specific chemical or its process. This method incorporates all data in the EDP and includes only one set of vent stream characteristics when applied. The median vent stream characteristics are simply the median of the chemical process method vent stream characteristics.

The plant capacities included in the RWC analysis are based on information contained in Table 9-10. In general, the smallest plant capacities that may be affected by the standards are selected for the RWC analysis. This includes small plants larger than 1 Gg/yr in capacity (i.e., larger than the exempted capacity). As with the vent stream characteristics, data do not exist for all chemicals being screened, so three procedures are used to determine the smallest plant capacities from available data in Table 9-10: (1) the chemical specific method; (2) the chemical process method; and (3) the median method.

The chemical-specific method is the same as before and uses chemical-specific data from Table 9-10 to determine the smallest plant capacity. This method is always used for chemicals in the screening analysis that have available chemical specific data listed in Table 9-10. The chemical process method is invoked when the chemical process associated with the production of a chemical is known, but chemical-specific capacity information is not available from Table 9-10. All the smallest capacities for chemicals produced by the same process are included to obtain a median smallest plant capacity for that process. The median method is used in cases where no information is available for a specific chemical or its process. This method incorporates all data in Table 9-10. The smallest plant capacity is assumed to be the median of the chemical process capacities.

In addition to the control cost assumptions, the RWC scenario incorporates several other conservative assumptions that tend to exaggerate projected price increases. First, although many chemicals are coproducts produced together in a single process or are byproducts of the production of another chemical, these chemicals do not share the costs of control, and each is assigned the full impact of control cost. If the coproducts and byproducts were omitted from the price impact model, the primary product (or subject chemical) would carry all the cost of control in its price, and the true cost

impact of the regulation would result. By assigning full cost pass-through to those coproducts and byproducts, another worst-case assumption is implemented in the RWC analysis. Table 9-21 shows a list of chemicals produced in a coproduct/byproduct reactor process.⁷⁰ As a result of this assumption, the price impacts for the chemical in the right column of Table 9-21, or the secondary product in a reactor process, are slightly exaggerated.

In addition, chemicals are assumed to have costs even if no expansion or replacement capacity is projected. Thus, a number of the 173 chemicals discussed in Section 9.1.6 that are not projected to grow are nevertheless costed. It is also assumed that firms producing chemicals thought to be combusted at baseline will nevertheless incur costs of control. This assumption implies that any process units producing these chemicals that are built to accommodate new growth or the retirement of existing process units will be built in areas in which regulations or other economic and/or safety considerations currently do not require combustion. A recent article confirms that this assumption fits an extreme worst-case scenario. The article predicts that the majority of forthcoming construction in the chemical industry will take place in areas where SIPs require controls similar to those of the NSPS.⁶⁹ If, in contrast, it had been assumed that all future process units would be built in areas with such regulations, the cost of control for these chemicals would be zero, and the rolled-through price impacts for the other chemicals would be lessened.

Finally, the roll-through logic of the price impacts model described in Section 9.2.2.1 also tends to reinforce the RWC assumptions. For some of the chemicals, two or three process routes are available. The model chooses among the various process routes possible for a given chemical and selects the route that produces the highest price increase.

The majority of the chemicals had very small price increases under the RWC assumptions. When the RWC costs were used, 36 percent of the 173 chemicals screened experienced no price increase due to zero cost assigned to chemical processes without vent streams. Of the 173, 61 percent experienced increases of between 0 and 5 percent. Six of the chemicals or 3 percent had price increases greater than 5 percent using the RWC costs. A complete list of the price increases for each of the chemicals is provided in Appendix H.

The chemicals with price increases greater than 5 percent using the RWC assumptions and the price increases associated with each are presented in Table 9-22. Also presented is information about the degree to which the chemical is likely to be affected by the regulation, including notes on the TRE value under RWC conditions and the amount of required capacity projected. Of the chemicals with high price increases, two are not projected to require any expansion or replacement capacity during the first 5 years of regulation, and three have no vents or are combusted at baseline. The remaining chemical has a vent stream assumed not combusted at baseline. This chemical, vinyl trichloride, has a very high TRE value under the RWC conditions. The higher the TRE value the less likely the chemical producer will be required to control under an NSPS.

TABLE 9-21. CHEMICAL COPRODUCTS AND BYPRODUCTS OF
PRINCIPAL SOCMI PRODUCT CHEMICALS⁷⁰

Principal product	Coproduct/byproduct
Methyl chloride	Chloroform
Carbon tetrachloride	Chloroform
Ethylene glycol	Diethylene glycol
Propylene	Ethylene
Dodecene	Tripropylene
Benzene	Toluene
Benzene	Xylene (mixed)
Benzene	o-Xylene
Benzene	p-Xylene
Perchloroethylene	Trichloroethylene
Ethylene glycol	Triethylene glycol

TABLE 9-22. CHEMICALS WITH PRICE INCREASES GREATER
THAN 5 PERCENT: REASONABLE WORST CASE SCREENING

ID	Name	Percentage price increase	Why the price increase will not materialize
51	Methyl chloride	7.98	Combusted at baseline
68	1,4-Dichlorobutene	5.14	No required capacity projected
73	Vinylidene chloride	19.21	Combusted at baseline
203	Methyl chloroform	11.11	No reactor-related vents at baseline
204	Vinyl trichloride	10.54	Large TRE
240	Chloroacetic acid	15.50	No required capacity projected

It is possible to recalculate the annual costs and subsequent price increases for vinyl trichloride assuming the plants producing it are required to control under certain regulatory alternatives. Using a TRE cutoff of \$2,500, Regulatory Alternative III, the highest possible costs that would be incurred if a chemical were to require controls are calculated. This would occur when the continually monitored TRE value falls below the level of \$2,500 per megagram of VOC controlled. Since the TRE value is defined as control cost per year divided by annual VOC emission rate, the maximum yearly control cost would be equal to \$2,500 times the annual VOC emission rate if Regulatory Alternative III were imposed. For vinyl trichloride, the annual costs of control are recalculated using the \$2,500 TRE limit and the amount of VOC controlled from the EDP. This annual cost represents the highest possible cost to a producer if he is required to install control equipment based on a TRE level below \$2,500. The price increase that results from the change in annual cost for vinyl trichloride drops substantially. Not only does this chemical fall below the 5 percent level, but also two chemicals it inputs into, vinylidene chloride, and methyl chloroform, fall below the 5 percent level. Therefore, although the prices of several chemicals appear to be significantly impacted under the RWC assumptions, it is unlikely that these effects would materialize.

Table 9-23 shows both the old and new price increases of these three chemicals, along with the other three chemicals. As mentioned earlier, however, these other three chemicals are either uncombusted at baseline or have no new or replacement capacity required. Under this analysis, then, no chemical new facilities built in the 1985 to 1990 period are expected to have a price increase greater than 5 percent..

9.2.2.3 More Likely Case Scenario. In addition to the RWC screening, a more likely case (MLC) scenario has also been developed. It provides a more likely projection of the impacts that will result from the regulation, in contrast to the exaggerated RWC impacts used for analysis of price increases due to an NSPS.

Under the MLC assumptions, only those chemicals that have vents, are uncombusted at baseline, and have projected need for additional capacity over the first 5 years of implementation are assigned control costs. Furthermore, chemicals with projected need for new capacity but without vents and chemicals with projected need for new capacity but with baseline combustion have zero control costs. The control costs developed for the MLC, like the RWC, are based on the vent streams in the EDP. The vent streams and control costs are scaled to each chemicals median process unit size, however, rather than to the smallest existing plant size. No TRE cutoff is applied, so that many chemicals that will not be required to be controlled are still given price increases.

A total of 43 chemicals experience some price increase under the MLC assumptions. Twenty-six of these are chemicals with assigned control costs; the remainder have those 26 chemicals as inputs. The results of the MLC

TABLE 9-23. PRICE INCREASES BEFORE AND AFTER
RECALCULATION OF ANNUAL CONTROL COST
FOR VINYL TRICHLORIDE^a

ID	Chemical name	Price increase, %	
		Before ^b	After
51	Methyl chloride	7.98	7.98
68	1,4-Dichlorobutene	5.14	5.14
73	Vinylidene chloride	19.21	2.56
203	Methyl chloroform	11.11	1.48
204	Vinyl trichloride	10.54	0.72
240	Chloroacetic acid	15.50	15.50

^aControl costs for vinyl trichloride and only for vinyl trichloride are assumed to be \$2500/mg of VOC controlled.

^bThese entries are from Table 9-22.

analysis indicate that none of the chemicals has a price increase greater than 5 percent. Most of the price increases are very small: 93 percent are under 1 percent. These results are used to estimate quantity and distributional impacts in subsequent sections of this chapter.

9.2.3 Other Economic Impacts

9.2.3.1 Quantity Impacts. The price increases estimated in the preceding section may have further economic impacts. Price increases induce consumers to reduce consumption, all other things being equal. This response is important because actual quantities traded at the new price level will decrease, and the production capacity actually installing controls will be reduced relative to projections given in Table 9-16. This reduction in the quantity of a chemical produced relative to the projection of production is termed the quantity impact of the regulation.

The magnitude of the quantity impact depends upon the price elasticity of demand, or the percentage change in quantity demanded in response to the percentage change in price. In mathematical terms, the price elasticity is defined in Equation (9-1):

$$\eta = -(\Delta Q / \Delta P) \times (P / Q), \quad (9-1)$$

where

η	=	price elasticity
ΔQ	=	change in quantity produced due to price increase
ΔP	=	change in price due to the NSPS (1982 \$)
Q	=	projected 1990 quantity produced
P	=	price before the NSPS (1982 \$).

The negative sign is a convention used to make the elasticity positive since quantity and price are normally inversely related.

Given η , P , Q , and ΔP , the quantity impact, ΔQ , due to a price increase can be estimated:

$$\Delta Q = -\eta \times Q \times \Delta P / P, \quad (9-2)$$

where

$\Delta P / P$	=	the proportionate change in price calculated in Section 9.2.2
Q	=	the value given in Table 9-18, column 1
η	=	0.7, the lower bound on the range of price elasticity for the chemical industry as a whole given in Section 9.1.

Table 9-24 shows the change in quantity produced due to the NSPS for the chemicals that have projected need for new capacity. Included in this table

TABLE 9-24. QUANTITY IMPACTS IN 1990 DUE TO
CONTROL COSTS REQUIRED BY THE REGULATION

Chemical name	1990 production, Gg	Rolled-through change in price from regulation, \$/Kg	Price, \$/Kg	Quantity impact, Gg
Adipic acid	719	0.17	132	0.65
Benzyl chloride	69	1.07	92	0.56
Butyl acrylate	118	0.12	150	0.07
n-Butyl acetate	71	0.16	106	0.08
t-Butyl alcohol	481	0.78	159	1.65
tert-Butyl hydroperoxide	52	1.03	100	0.37
Chlorobenzene	143	0.61	84	0.73
p-Chloronitrobenzene	52	2.61	174	0.55
Cyanuric chloride	52	2.10	319	0.24
Diacetone alcohol	26	0.51	112	0.08
Diethylbenzene	52	0.22	218	0.04
2,4-(and 2.6)-Dinitrotoluene	52	0.62	201	0.11
2,4-Dinitrotoluene	324	0.34	196	0.39
Ethyl acetate	127	0.28	95	0.26
Ethyl acrylate	167	0.23	123	0.22
Ethylbenzene	4,843	0.02	71	0.95
Ethylene oxide	2,661	0.58	70	15.43
Isopropyl alcohol	987	0.08	73	0.76
Methyl methacrylate	590	0.06	137	0.18
Nitrobenzene	600	0.03	75	0.17
1-Phenylethyl hydroperoxide	52	1.22	100	0.44
Phenylpropane	52	0.20	91	0.08
Propylene oxide	1,389	0.05	99	0.49
Trimethylene	52	0.34	120	0.10
Vinyl acetate	1,209	0.02	71	0.24
Vinyl trichloride	116	0.87	75	0.94

are the original production projections for 1990, before any quantity impacts were accounted for, and the change in price using more-likely-case assumptions.

The quantity impacts shown in Table 9-24 not only influence the employment level and capital expenditures discussed later in Section 9.2.3.3, but also influence the projections of future need for capacity and thus the potential emissions reduction of the standard. If quantity produced is diminished in 1990 from its value projected in Section 9.1.6, then it is possible that fewer process units will be constructed, and that emissions reduction brought about by the standard will fall. On the other hand, the quantity impact may effect decreases in production from existing units only, or may simply lower industry capacity utilization, and emissions reductions will stay the same. Since the magnitude of the impacts are less than 1 Gg for most chemicals, it is likely that all projected process units will be built, and the industry will absorb the reduction in quantity produced.

As noted in Section 9.1, a single measure of price elasticity applied to all chemicals does not take into account each chemical's particular response to changes in the market price. The quantity impacts may vary from those projected here if a different measure of price elasticity applies. For example, the actual price impacts may induce producers to use substitutes, either in the production process of the chemical or for the chemical itself. If this is the case, the opportunity to use a close substitute would tend to raise a chemical's price elasticity to a higher negative value closer to -1, yielding a correspondingly larger quantity impact for each. The availability of good substitutes and whether the substitutes themselves will be regulated are major factors in determining the price elasticity appropriate to a given chemical. In this analysis, however, the computation of chemical-specific elasticities is ruled out because of the lack of publicly available elasticity estimates for these chemicals and the analytical resources that would have been required to estimate them independently.

9.2.3.2 Distributional Impacts. The proposed NSPS would require controls only on selected expansion or replacement capacity additions. Existing facilities will, however, be affected by the price impacts. In particular, established facilities would derive extra revenue as chemical prices increase while production costs remain level. The total of the output from the unaffected firms times the change in price represents a transfer of income (additional consumer expenditures) from chemical consumers to producers. This transfer is a distributional impact of the standard. In this analysis, it is assumed that no delay in plant retirement will occur because of the standard.

The distributional impact is calculated as the change in price from the regulation times the output (in 1990) provided by process units that are built prior to 1985 and are therefore not affected by regulation. This output is calculated from 1990 production projections by subtracting 85 percent of the projected additions to capacity in 1985-1990.

For the distributional impacts, the change in price is calculated differently from the roll-through price change used in the quantity impact analysis. If a rolled-through price increase were used, the additional consumer expenditures transferred to existing facilities would be double counted for all intermediate chemical price effects. While it is true that the selling price must increment through the roll-through process, the aggregation of intra-industry expenditures must not be added to the end-product consumer expenditure or they would be counted more than once in the final amount. Therefore, the change in price is calculated directly from the dollar cost of regulation for the median-sized capacity plant projected for each chemical. The dollar cost per plant size is converted to $\text{\$/kg}$ to obtain the change in price, assuming that the entire cost will be passed on to consumers. This is the total price change when the quantity impact associated with the price change is less than 0.85 times the additional capacity projected in 1990.

Table 9-25 shows these distributional impact values for the chemicals effecting price changes. Also shown is the direct change in price from the regulation converted to dollars per gigagram and projected required capacity from Table 9-19. This direct price change is calculated as the MLC control cost divided by the production volume of the median-size process unit needed to accommodate projected 1990 capacity. Based on these preliminary figures, the distributional impact amounts to about \$24 million per year. This transfer of consumer expenditures to established producers would continue in diminishing amounts for the life of the established plants.

The implications of a distributional impact are in the possible postponement of plant retirement due to age. Though old facilities and technology might become inefficient, the increased revenue without the accompanying control cost increases would provide incentive to keep the otherwise outdated equipment on line. Since the minimum amount of additional capacity that is required to meet growth in consumption by 1990 is determined in part by an estimate of plant retirement from 1985-1990, this incentive could delay or cancel the construction of some of the process units projected to be built in 1990. If this happens, the emissions reduction achieved by the standard would be somewhat diminished. It is not currently known whether the distributional incentive to operate outdated process units is larger than the incentive to retire the inefficient units.

9.2.3.3 Employment and Capital Requirements. The level of employment, the amount of required capacity constructed, and the total capital investment are directly affected by NSPS-induced changes in quantity produced.

The impact of the NSPS on employment levels is a result of the quantity impact. Because the overall production in the impacted firms is lowered by price increases, fewer workers are needed in the production process. The necessity of hiring additional workers to operate the control devices would help balance the decrease. Little effect would probably be felt in the chemicals industry, which employs almost 150,000 workers. Some impacts may

TABLE 9-25. DISTRIBUTIONAL IMPACTS IN 1990 DUE TO CONTROL COSTS REQUIRED BY THE REGULATION

Chemical name	Existing producers production in 1990	Direct change in price	Distributional impacts
Adipic acid	317.8	1,679.47	533,737.0
Benzyl chloride	38.4	10,747.33	412,697.6
Butyl acrylate	88.3	1,244.23	109,803.2
n-Butyl acetate	51.5	1,610.26	82,847.9
t-Butyl alcohol	404.5	7,766.40	3,471,580.8
tert-Butyl hydroperoxide	42.7	6,167.27	263,034.2
Chlorobenzene	85.2	6,051.35	515,575.3
p-Chloronitrobenzene	36.7	21,212.22	778,488.6
Cyanuric chloride	36.7	21,050.00	772,535.0
Diacetone alcohol	8.2	5,111.43	41,658.1
Diethylbenzene	36.7	2,021.78	74,199.2
2,4-(and 2.6)-Dinitrotoluene	37.5	6,177.59	231,968.4
2,4-Dinitrotoluene	256.0	3,374.82	863,955.2
Ethyl acetate	76.0	2,750.40	209,030.4
Ethyl acrylate	133.0	2,493.55	246,861.4
Ethylbenzene	2,680.6	177.14	474,854.0
Ethylene oxide	2,140.8	5,757.80	12,326,306.6
Isopropyl alcohol	811.9	824.19	669,159.3
Methyl methacrylate	267.0	625.20	166,928.4
Nitrobenzene	469.9	256.58	120,577.5
1-Phenylethyl hydroperoxide	36.7	11,932.44	437,920.7
Phenylpropane	36.7	2,021.78	74,199.2
Propylene oxide	841.6	536.94	451,892.2
Trimethylene	36.7	3,403.89	124,922.7
Vinyl acetate	552.8	185.37	102,471.4
Vinyl trichloride	77.8	8,686.33	675,362.4
Total			24,232,566

be felt in the construction industry if capacity expansions are not pursued when demand decreases in response to price increases. Given the size of the industry and the small level of output reduction relative to projected increases, these employment effects are relatively small.

Capital requirements for reactor process NSPS also would be small. The debt ratio for the chemicals industry is estimated using long-term debt of \$37.2 million and stockholder's equity of \$93.2 million, as shown in Table 9-13, and equals 28.5-percent. This value represents the debt ratio that is incurred normally without expenditure for NSPS controls. An estimate of capital cost of NSPS controls for a median-size plant is obtained from the total capital cost of the recommended Regulatory Alternative III in Table 9-20 divided by the projected number of facilities required to control under that alternative. A capital investment in control equipment of \$0.84 million per facility results from this calculation. This increase in capital investment of \$0.84 million to install VOC emission controls under median control conditions would increase the overall industry debt ratio to 29 percent if financed entirely from debt sources. This half a percentage point change in debt ratio is modest and could be limited even further if part of the control investments were not funded by debt.

9.3 REGULATORY, INFLATIONARY, SOCIOECONOMIC, AND SMALL BUSINESS IMPACTS

9.3.1 Executive Order 12291

Executive Order 12291 requires the conduct of a regulatory impact analysis (RIA) of a proposed regulation if the regulation is likely to result in

- An annual effect on the economy of \$100 million or more;
- A major cost or price increase for consumers; individual industries; Federal, State, or local government agencies; or geographic regions; or
- Significant adverse effects on competition, employment, investment, productivity, innovation, or ability of U.S.-based enterprises to compete with foreign-based enterprises in domestic or foreign markets.

An RIA is somewhat more comprehensive than the analysis described in this document. Among other things, RIAs contain a full examination of the air quality benefits--not just emission reductions--associated with NSPS. The cost impacts calculated in Chapter 8 and discussed in Chapter 9 for the years 1985 to 1990 for all regulatory alternatives indicate that the annual cost impact would be substantially less than \$100 million per year. As shown in Table 9-20, the fifth-year annualized cost requirements of the most stringent regulatory alternative amount to only \$9.3 million. For Regulatory Alternative III, these costs are only \$3.7 million.

The price impacts presented in Section 9.2.2 indicate that under the RWC, inflationary impacts may exceed 5 percent for three chemicals. However, none of the chemicals with high price increases has both process units projected and a low TRE value. Under the more likely case assumptions, no chemicals experience a price increase greater than 5 percent.

Based on these results, the proposed standards do not qualify as major regulatory action under the criteria enumerated above: the annual effect on the economy is substantially less than \$100 million, the price impacts are small, and the standard will not have a significant effect on the operation of the domestic economy or its international trade. Therefore, a regulatory impact analysis and associated benefit/cost calculations are not given here. While this is the case, it is still worthwhile to note, in a qualitative fashion, the benefits against which the costs discussed above should be balanced.

The standards will reduce the rate of emission of VOCs to the atmosphere. These compounds are precursors of photochemical oxidants, particularly ozone. The EPA publication Air Quality Criteria for Ozone and Other Photochemical Oxidants⁷¹ explains the effects of exposure to elevated ambient concentrations of oxidants. (The problem of ozone depletion of the upper atmosphere and its relation to this standard are not addressed here.) These effects include

- Human health effects. Ozone exposure has been shown to cause increased rates of respiratory symptoms such as coughing, wheezing, sneezing, and shortness of breath; increased rates of headache, eye irritation, and throat irritation; and increases in the number of red blood cells. One experiment links ozone exposure to damage to human chromosomes.
- Vegetation effects. Reduced crop yields as a result of damage to leaves and/or plants have been shown for several crops including citrus, grapes, and cotton. The reduction in crop yields was shown to be linked to the duration of ozone exposure.
- Materials effects. Ozone exposure has been shown to accelerate the deterioration of organic materials such as plastics and rubber (elastomers), textile dyes, fibers, and certain paints and coatings.
- Ecosystem effects. Continued ozone exposure has been shown to be linked to the disappearance of trees such as Ponderosa and Jeffrey Pines and the death of predominant vegetation. Hence continued ozone exposure places a stress on the ecosystem.

In addition to reducing the severity of the physical and biological effects enumerated above, the regulatory action is likely to improve the aesthetic and economic value of the environment through, for example, beautification of natural and undeveloped land because of increased vegetation, improved visibility, and reduced incidence of noxious odors.

9.3.2 Small Business Impacts

The Regulatory Flexibility Act (Public Law 96-354, September 18, 1980) requires that agencies give special consideration to the impacts on small firms, organizations, and governments of all proposed regulations. Specifically, if a proposed regulation is likely to adversely effect small entities then the agency must perform a Regulatory Flexibility Analysis. According to EPA guidelines, an "adverse effect" on small entities is defined both in terms of the percentage of small firms affected by the regulation and the significance of the economic impact. A proposed regulation is considered to have an adverse effect on small firms when the percentage of small firms affected is substantial (i.e., at least 20 percent), and the economic impact on these firms is significant (i.e., price increases of at least 5 percent).⁷²

To satisfy the specific requirements of the Regulatory Flexibility Act, this analysis shows that the number of small firms affected by the regulation does not constitute a substantial percentage of small firms in the industry, and therefore there is no adverse effect and no need for a Regulatory Flexibility Analysis. Further, additional analyses of the number of small and large firms in the industry affected by the standards show that the larger firms will bear the majority of the burden of control cost, and that the potential burden of cost on small firms is not disproportionate to their contributions to emissions.

9.3.2.1 Regulatory Flexibility Act Considerations. In order to identify whether a substantial number of small firms are affected, the set of small firms in the industry is first defined. Then the number of small firms producing the chemicals with uncombusted vents and projected growth for the 5-year period of analysis are identified.

The standards for classifying a business as small are those set forth by the Small Business Administration (13 CFR Part 121), which determine that a small business in the organic chemicals industry can have no more than 750 employees for SIC 2865 and 1,000 employees for SIC 2869.⁷³ Other characteristics such as independent ownership and nondominance in its field of operation typify a small firm. According to the Bureau of Census there are 347 small firms in the chemical industry categories SIC 2865 and SIC 2869 based on these classification standards.⁷⁴ These SIC industries are assumed to represent the organic chemical industry.

According to current sources, there are 55 firms that produce the 26 chemicals with uncombusted vents and projected growth shown in Table 9-19. (Recall that all 26 chemicals would be affected only under the most stringent regulatory alternative, and that many fewer will be impacted under less stringent regulatory alternatives). Employment data are available for 46 of the 55 firms currently producing the 26 chemicals. Only 7 of the 46 firms are considered small businesses based on available employment data.⁴¹ Therefore, the proportion of small firms potentially impacted to small firms in the industry is 7 to 347, or only 2.0 percent. Even if it is assumed that

all 9 firms for which there are no employment data available are also small, the percentage of potentially impacted small firms in the industry is only 4.6 percent. Both of these percentages are well below 20 percent.

Though the analysis in Section 9.2.2 shows that this regulation may have significant impacts on a few small firms under worst case assumptions, the number of these firms is far from substantial, and a Regulatory Flexibility Analysis is not required.

9.3.2.2 Burden of Cost Analysis. There is another way to look at the question of whether this NSPS will place an undue burden on small firms. This is to compare the portion of small (or large) firms potentially impacted by the NSPS with the proportion of small (or large) firms in the industry. This comparison indicates that the NSPS may favor small firms vis-a-vis large firms.

A total of 517 firms are included in SIC 2865 and SIC 2869. Thus, about 67 percent (347 divided by 517) of firms in the organic chemical industry are considered small. Even if the 9 firms for which no data are available are assumed to be small, only 16 out of 55, or 29 percent of the firms potentially impacted by the regulation are small. If it is assumed that the distribution of facility ownership by firm size will be the same for new facilities as for existing facilities, only 29 percent of the firms potentially impacted under the NSPS in the first 5 years will be small even though 67 percent of the firms in the overall industry are small. On the other side of the coin, there is a greater percentage of potentially impacted firms that are large (71 percent) than the percentage of large firms in the industry (33 percent).

Though the large firms bear a burden of the total industry cost disproportionate to their overall number, the cost they bear will be proportional to their level of emissions, assuming that emissions levels are proportional to production. Based on this evidence it is most likely that the burden of the standard will fall predominately on those firms responsible for most of the total emissions.

9.4 IMPACTS OF THE ACCUMULATION OF COSTS FROM THE REACTOR PROCESS NSPS AND OTHER AIR QUALITY STANDARDS

This section describes the potential organic chemical product price increases due to production cost increases resulting from the fifth-year cost of seven air pollution control regulations developed since August 1977: the benzene fugitive emissions NESHAP, VOC fugitive emissions NSPS, the VOC fugitive emissions from petroleum refining, the volatile organic liquid storage tanks NSPS, the distillation NSPS, the air oxidation NSPS, and the reactor processes NSPS. This section also examines potential changes in production of organic chemicals due to price increases from control costs. Section 8.6 gives a full account of the methodology used to estimate these cumulative costs, and Table 8-11 provides the total direct costs of the seven potential emissions regulations for 26 reactor process chemicals that have projected required capacity for the 5-year period beginning in 1985.

9.4.1 Price Impacts of Cumulative Costs

The price increase analysis is conducted on a chemical-specific basis assuming that total cumulative costs are passed through completely to consumers of the chemicals. Total fifth-year annualized costs are based on the projections of the number and size of facilities for 26 reactor process chemicals listed in Table 9-19. This analysis calculates the direct price increases associated with control costs as the fifth-year 1990 cumulated cost for each chemical divided by the total projected production increase of that chemical in 1985-1990, as shown in Table 9-19. The direct percentage price increase, given in cents per kilogram after multiplying by the proper conversion scalar, is shown in the third column of Table 9-26.

Also shown in Table 9-26 is the rolled-through price increase from the accumulation of costs from the five potential standards. A rolled-through price increase results from the aggregation of individual price increases of input chemicals along a production chain. The computer model used in the price analysis of Section 9.2.2 incorporates the process routes for each of the 26 chemicals and traces cumulated control costs through the series of chemicals that are input along a given process route. The results from this rolled-through calculation are shown in the fourth column of Table 9-26.

The results of the price increase analysis show that none of the 26 chemicals is expected to have a price increase greater than 5 percent.

9.4.2 Quantity Impacts of Cumulative Costs

The rolled-through price increases estimated in the preceding section may have economic impacts. Price increases induce consumers to reduce consumption, all other things being equal. This response is important because actual quantities traded at the new price level will decrease, causing production decisions to be altered. This reduction in the quantity of the chemical produced is termed the quantity impact of a price increase due to regulation.

The magnitude of the quantity impact depends on the price elasticity of demand, or the percentage change in quantity demanded in response to the percentage change in price. Equation 9-1 gives the price elasticity of demand and provides the means with which to calculate the quantity impact from the cumulated rolled-through price increases in Table 9-26. The quantity impact is calculated as described in Section 9.2.3.1 using the figure of -0.7 for the price elasticity, the projection of production in 1990 for quantity, the price in cents per kilogram before the regulation in 1982 dollars for the price, and the rolled-through cumulated cost increase for the change in price. Table 9-27 shows the results in reduction of quantity supplied and the percentage change in quantity produced in 1990 due to the fifth-year cumulated costs of control from the seven emission standards.

TABLE 9-26. PRICE IMPACTS OF CUMULATED COSTS FROM SEVEN AIR QUALITY STANDARDS FOR 26 REACTOR PROCESS CHEMICALS

Chemical	Price ^a ¢/kg	Change in price, ¢/kg	Direct cost price increase, %	Rolled- through cost price increase, %
Adipic acid	132	0.22	0.16	0.16
Benzyl chloride	92	1.40	1.52	1.52
Butyl acrylate	150	0.46	0.31	0.31
n-Butyl acetate	106	0.67	0.63	0.63
t-Butyl alcohol	159	3.12	1.96	1.96
t-Butyl hydroperoxide	100	0.39	0.39	3.35
Chlorobenzene	84	0.86	1.03	1.03
p-Chloronitrobenzene	174	2.77	1.59	1.99
Cyanuric chloride	319	2.76	0.86	0.86
Diacetone alcohol	112	2.18	1.95	1.95
Diethylbenzene	218	2.18	1.95	1.95
2,4-(and 2,6)-Dinitrotoluene	201	1.31	0.65	0.65
2,4-Dinitrotoluene	196	0.48	0.25	0.25
Ethyl acetate	95	1.06	1.11	1.11
Ethyl acrylate	123	0.50	0.41	0.41
Ethyl benzene	71	0.06	0.09	0.09
Ethylene oxide	70	0.63	0.90	0.90
Isopropyl alcohol	73	0.14	0.19	0.19
Methyl methacrylate	137	0.19	0.14	0.14

See footnotes at end of table.

(continued)

TABLE 9-26 (continued)

Chemical	Price ^a ¢/kg	Change in price, ¢/kg ^b	Direct cost price increase, %	Rolled- through cost price increase, %
Nitrobenzene	75	0.16	0.22	0.22
1-Phenylethyl hydroperoxide	100	1.84	1.84	1.92
Phenylpropane	91	0.85	0.94	0.94
Propylene oxide	99	0.09	0.09	0.09
Trimethylene	120	0.99	0.83	0.83
Vinyl acetate	71	0.08	0.11	0.11
Vinyl trichloride	75	1.13	1.51	1.51

^aPrice in cents per kilogram from Table 9-1.

^bChange in price is calculated by dividing cumulated cost (from Table 8-11) by projected additional capacity in 1990.

TABLE 9-27. QUANTITY IMPACTS OF CUMULATED COSTS FROM SEVEN AIR
QUALITY STANDARDS FOR 26 REACTOR PROCESS CHEMICALS

Chemical	Quantity impact, Gg	1990 production, ^a Gg	Percent change in 1990 production
Adipic acid	0.84	719	0.12
Benzyl chloride	0.73	69	1.07
Butyl acrylate	0.25	118	0.21
n-Butyl acetate	0.31	71	0.44
t-Butyl alcohol	6.61	481	1.37
t-Butyl hydroperoxide	1.22	52	2.34
Chlorobenzene	1.02	143	0.72
p-Chloronitrobenzene	0.72	52	1.39
Cyanuric chloride	0.31	52	0.61
Diacetone alcohol	0.35	26	1.36
Diethylbenzene	0.15	52	0.30
2,4-(and 2,6)-Dinitrotoluene	0.24	52	0.46
2,4-Dinitrotoluene	0.56	324	0.17
Ethyl acetate	0.99	127	0.78
Ethyl acrylate	0.48	167	0.28
Ethyl benzene	2.86	4,843	0.06
Ethylene oxide	16.76	2,661	0.63
Isopropyl alcohol	1.33	987	0.13
Methyl methacrylate	0.57	590	0.10
Nitrobenzene	0.90	600	0.13
1-Phenylethyl hydroperoxide	0.70	52	1.34

See footnote at end of table.

(continued)

TABLE 9-27. (continued)

Chemical	Quantity impact, Gg	1990 production, ^a Gg	Percent change in 1990 production
Phenylpropane	0.34	52	0.65
Propylene oxide	0.88	1,389	0.06
Trimethylene	0.30	52	0.30
Vinyl acetate	0.95	1,209	0.08
Vinyl trichloride	1.22	116	1.05

^aProjected production in 1990 from Table 9-18.

Column three of Table 9-27 shows that none of the changes in production decisions due to the cumulated price increases detailed in Section 9.4.1 constitutes more than 1.37 percent of the total projected production of any chemical and is less than 1 percent for most chemicals. The absolute change in production (the quantity impact) is less than 2 Gg for all but two of the chemicals. These chemicals, ethylene oxide, and butyl alcohol have a relatively large amount of projected output in 1990.

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APPENDIX A
EVOLUTION OF THE PROPOSED STANDARDS

APPENDIX A
EVOLUTION OF THE PROPOSED STANDARDS

The purpose of this study was to develop new source performance standards for reactor processes in the synthetic organic chemicals' manufacturing industry (SOCMI). Work on this study was begun on October 25, 1982, by Radian Corporation under the direction of the Office of Air Quality Planning and Standards (OAQPS), Emission Standards and Engineering Division (ESED). The decision to develop these standards was made on the recommendation of the Environmental Protection Agency (EPA) in conformity with its policy to develop generic standards for the SOCMI.

The chronology, which follows, lists important events that have occurred in the development of background information for new source performance standards for reactor processes in the SOCMI.

<u>Date</u>	<u>Activity</u>
October 25, 1982	EPA project kickoff meeting.
December 8, 1982	Phase I workplan completed.
January 28, 1983	Source Category Survey Report (SCSR) completed.
February 28, 1983	Completed final concurrence memorandum recommending continuation of the reactor processes NSPS development.
February 16, 1983	Held meeting with EPA to discuss direction of project continuation.
March 21, 1983	Phases II and III workplan completed.
May 6, 1983	Developed updated comprehensive list of chemicals produced in capacities greater than 100 million lbs per year.
May 6, 1983	Submitted SCSR to the Chemical Manufacturers Association (CMA) and other trade groups for their review and comment.
June 8, 1983	Submitted SCSR to environmental groups for review and comment.
July 19, 1983	Visited Monsanto Fibers and Intermediates Company at Houston, Texas.
July 20, 1983	Visited the Texas Air Control Board at Houston, Texas
September 28, 1983	Completed the industry profile (Section 9.1 of BID) containing growth projections and general industry statistics.
September 29, 1983	Meeting held with members of the CMA to discuss SCSR and overall reactor processes NSPS development.

<u>Date</u>	<u>Activity</u>
October 5, 1983	Visited Witco Chemical Company at Houston, Texas.
October 6, 1983	Visited Dow Chemical at Freeport, Texas.
October 11, 1983	Visited Tennessee Eastman Company at Kingsport, Tennessee.
November 1983	Received Office of Management and Budget approval for Section 114 questionnaires; completion of first-round regulatory analyses.
November 15, 1983	Developed affected facility and other definitions.
December 19, 1983	Meet with EPA Branch Chiefs on the status of the reactor processes project.
December 1983	Decision made to revise the growth projections for reactor process facilities and to include flares specifically in the regulatory analysis.
January 10, 1984	Completed first draft list of potential Section 114 letter contacts.
January 11, 1984	Meeting between EPA/CPB and SDB held to resolve issues on the regulatory alternatives.
February 3, 1984	Submitted 20 Section 114 letters to respondents requesting information on 24 chemicals; identified production capacities and vent stream characteristics for chemicals covered by standards.
February 28, 1984	Completed concurrence memorandum on the regulatory alternatives.
March 12, 1984	Completed and sent BID Chapters 3-6 to industry for comment.

<u>Date</u>	<u>Activity</u>
March 20, 1984	Held meeting to discuss revisions to the flare and incinerator costing procedures.
March 30, 1984	Completed draft preamble and regulation.
April 24, 1984	Meet with EPA/CPB to discuss industry comments on flare costing algorithms.
April 27, 1984	Completed concurrence memorandum on the basis of the standards.
May 17, 1984	Meeting held to resolve preamble and regulation issues.
May 25, 1984	Completed a memorandum documenting changes made to flare and incinerator algorithms.
June 1984	Revisions made to regulatory analysis; developed total resource effectiveness (TRE) coefficients for the regulation.
June 22, 1984	Developed revised list of large volume chemicals for the reactor processes standards.
July 12, 1984	Sent NAPCTAC package to participants.
July 25, 1984	Sent Working Group package to group members.
July 27, 1984	Docket opened.
August 1, 1984	Meet with Research Triangle Institute to discuss the chemical price screening.
August 29, 1984	Meeting of NAPCTAC in Durham, N.C., at which the Texas Chemical Council made a presentation.
September 14, 1984	Completed NAPCTAC issues summary.
October 1984	Started revisions of flare and incinerator costing algorithms based on industry comment received on costs used for other SOGMI standards; completed development of low flowrate and low production capacity cutoffs.

<u>Date</u>	<u>Activity</u>
October 24, 1984	Meet with EPA to establish procedures for the chemical price screening analyses.
November 1, 1984	Meet with EPA to discuss recommended revisions to flare and incinerator costing algorithm; discussed impact of revisions.
December 26, 1984	Sent Steering Committee package to committee members.
January 1985	Initiated work on the final Assistant Administrator proposal package.
February 11, 1985	Completed work on the chemical price screening analysis.

APPENDIX B
INDEX TO ENVIRONMENTAL IMPACT CONSIDERATIONS

APPENDIX B
INDEX TO ENVIRONMENTAL CONSIDERATIONS

This appendix consists of a reference system which is cross indexed with the October 21, 1974 Federal Register (39 FR37419) containing EPA guidelines for the preparation of Environmental Impact Statements. This index can be used to identify sections of the document that contain data and information germane to any portion of the Federal Register guidelines.

APPENDIX B
INDEX TO ENVIRONMENTAL IMPACT CONSIDERATIONS

Agency Guidelines for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Background Information Document (BID)
1. Background and Description of Proposed Action	
Summary of Regulatory Alternatives	A range of regulatory alternative control levels is discussed in Section 6.2.
Statutory Basis for the Standard	The statutory basis for the standard is given in Chapter 2.
Facilities Affected	A description of the facilities to be affected is given in Chapter 6.
Process Affected	A description of the processes to be affected is given in Chapter 3, Sections 3.3 and 3.5.
Availability of Control Technology	Information on the availability of control technology is given in Chapter 4.
Existing Regulations at State or Local level	A discussion of existing regulations on the industry to be affected by the standards is included in Chapter 3, Section 3.4.2.
2. Alternatives to the Proposed Action	
Description of Range of alternatives examined	The definition of the available range of control alternatives is presented in Chapter 6, Section 6.3.

APPENDIX B
INDEX TO ENVIRONMENTAL IMPACT CONSIDERATIONS
(CONCLUDED)

Agency Guidelines for Preparing Regulatory Action Environmental Impact Statements(39 FR 37419)	Location Within the Background Information Document (BID)
3. Environmental Impacts	
Air Pollution	The air pollution impact of the control alternatives are considered in Chapter 7, Section 7.2.
Water Pollution	The impact of the control alternatives on water pollution are considered in Chapter 7, Section 7.3.
Solid Waste Disposal	The impact of the control alternatives on solid waste disposal are considered in Chapter 7, Section 7.4.
4. Energy	The impact of the control alternatives on energy use are considered in Chapter 7, Section 7.5.
5. Other Impacts	Other impacts associated with the control alternatives are evaluated in Chapter 7, Sections 7.6 and 7.7.
6. Costs	The national cost impact of the control alternatives is considered in Chapter 8, Section 8.5.

APPENDIX C
EMISSION DATA PROFILE

APPENDIX C. EMISSION DATA PROFILE

Unit Process I.D.	Chemical	Plant Production (10 ⁶ lb/yr)	Sequential Listing of All Vent Gas Treatment Devices ^b	Process Vent Stream Characteristics ^c		
				Flow (scfm)	Heat Value (Btu/scf)	VOC (lb/hr)
ALK-1	Linear Alkylbenzene	250	HCL/VOC Scrubbers	DNA ^d	DNA	DNA
ALK-2	Linear Alkylbenzene	DNA	-	NO	REACTOR	VENTS
ALK-3	Ethylbenzene	1,795	VOC Scrubber	17	PROCESS	16
ALK-4	Tetra Ethyl - Tetra Methyl Lead	175	Condenser/Incinerator	DNA	DNA	DNA
ALK-5	Ethylbenzene	147	Condenser/VOC Scrubber	8.7	DNA	0.1
ALK-6	Linear Alkylbenzene	243	Acid Gas Scrubber/Flare	DNA (Low flow)	DNA	DNA
ALK-7	Linear Alkylbenzene	140	VOC/HCL Scrubbers	NO	REACTOR	DNA
ALK-8	Cumene	700	-	NO	REACTOR	VENTS
ALK-9	Cumene	230	-	NO	REACTOR	VENTS
ALK-10	Cumene	450	-	NO	REACTOR	VENTS
ALK-11	Cumene	400	-	NO	REACTOR	VENTS
ALK-12	Cumene	DNA	-	NO	REACTOR	VENTS
ALK-13	Diethyldichlorosilane	DNA	-	NO	REACTOR	VENTS
ALK-14	Nonylphenol	DNA	-	NO	REACTOR	VENTS
AMH-1	Caprolactam	280	-	NO	REACTOR	VENTS
AMH-1	Ethanolamines	125	-	NO	REACTOR	VENTS
AMH-2	Ethanolamines	40	-	NO	REACTOR	VENTS
CAR-1	Acetic Acid	100	VOC Scrubber/Flare	DNA	DNA	DNA
CAR-2	Methanol	1,484	Process Heater	(18,950) ^e	(295)	(75)
CAR-3	Methanol	590	Process Heater	DNA	DNA	DNA
CAR-4	Methanol	1,070	Process Heater	DNA	DNA	DNA
CLE-1	Phenol/Acetone	500	-	NO	REACTOR	VENTS
CHL-1	Ethylene Dichloride	550	HCL Scrubber/Incinerator	(167)	(163)	(74)
CHL-2	Chlorobenzene	60	Condenser/Scrubber	DNA	DNA	2
CHL-4	Chlorobenzene	73	HCL Scrubber	55	DNA (Assumed 0)	4
CHL-5	Ethylene Dichloride	500	-	NO	REACTOR	VENTS
CHL-6	Ethylene Dichloride	700	Incinerator	DNA	DNA	DNA
CHL-7	Ethylene Dichloride	847	Condenser/Incinerator	DNA	DNA	DNA
CHL-8	Methylene Chloride	DNA	-	NO	REACTOR	VENTS
CHL-9	Ethylene Dichloride	100	HCL Scrubber	40	PROCESS	3.6
CHL-10	Ethylene Dichloride	100	Condenser/Incinerator	(267)	(1,228)	(113)
CHL-11	Methylene Chloride	42	-	NO	REACTOR	VENTS
CHL-12	1,4-Dichlorobutene	DNA	Condenser/Scrubber	9,195	0	7.2
CHL-13	Methylchloroform	DNA	-	NO	REACTOR	VENTS
CHL-14	Allyl Chloride	250	-	NO	REACTOR	VENTS
CHL-15	Nano Chloroacetic Acid	DNA	VOC Scrubber	DNA	DNA	DNA

APPENDIX C. EMISSION DATA PROFILE (Continued)

Unit Process I.D.	Chemical	Plant Production (10 ³ lb/yr)	Sequential Listing of All Vent Gas Treatment Devices	Process Vent Stream Characteristics ^c		
				Flow (scfm)	Heat Value (Btu/scf)	VOC (lb/hr)
COM-1	Acetic Anhydride	300	Boiler	(147)	(1,069)	(306)
COM-2	Acetic Anhydride	600	Boiler	DNA	DNA	DNA
COM-3	Acetic Anhydride, ethoxylated	DNA	-	NO	REACTOR	VENTS
COM-4	Bisphenol - A	DNA	-	NO	REACTOR	VENTS
CBE-1	Benzene	DNA	Condenser/Flare	(1,209)	(206)	(0.3)
DEHY-1	Urea	DNA	M ₃ Scrubber	DNA	DNA	0
DEH-1	Acetone	73	VOC Scrubber	DNA	DNA	DNA
DEH-2	Methyl Ethyl Ketone	DNA	VOC Scrubber/Flare	DNA	DNA	DNA
DEH-3	Styrene	548	Process Heater	(5,208)	(280)	(711)
DEH-4	Styrene	112	Condenser/Flare	(574)	(300)	(161)
DEH-5	n-Paraffins	DNA	Process Heater	DNA	DNA	DNA
DEH-6	Acetone	8	-	NO	REACTOR	VENTS
DEH-7	Acetone	120	-	NO	REACTOR	VENTS
DEH-8	Acetone	DNA	-	NO	REACTOR	VENTS
DEH-9	Methyl Ethyl Ketone	12	-	NO	REACTOR	VENTS
DEH-10	Methyl Ethyl Ketone	DNA	-	NO	REACTOR	VENTS
DEH-11	Methyl Ethyl Ketone	70	Hydrogen System/Flare	DNA	DNA	DNA
DEH-12	Cyclohexanone	DNA	Boiler	DNA	DNA	DNA
DEMC-1	Vinylidene Chloride	75	Incinerator/MCL Scrubber	(10)	(600)	(41)
DEMC-2	Vinylidene Chloride	73	-	NO	REACTOR	VENTS
DEMC-3	Vinylidene Chloride	DNA	Condenser/Incinerator	DNA	DNA	DNA
EST-1	Ethyl Acrylate	90	No Controls	75	102	6.1
EST-2	Methyl Methacrylate	148	Incinerator	DNA	DNA	0.1
EST-3	Ethyl Acetate	DNA	Condenser	DNA	DNA	0.1
EST-4	Diethyl phthalate	200	Condenser	5	DNA (Assume 102)	0.1
EST-5	Diethyl Terephthalate	DNA	-	NO	REACTOR	VENTS
EST-6	Ethyl Acetate	30	Condenser	7	DNA (Assume 102)	0.5
EST-7	Butyl Acetate	45	Condenser	2	DNA (Assume 102)	0.1
EST-8	Ethylene Glycol	DNA	Condenser	8	DNA (Assume 102)	20 ^d
ETH-1	MIBC	DNA	-	NO	REACTOR	VENTS
ETHY-1	Butynediol	DNA	Stripper	9.2	747	19.8
FLU-1	Freon - 12	DNA	-	NO	REACTOR	VENTS
FLU-2	Freon - 113	DNA	-	NO	REACTOR	VENTS
FLU-3	Freon 11,12,113,114,22	DNA	-	NO	REACTOR	VENTS

APPENDIX C. EMISSION DATA PROFILE (Continued)

Unit Process I.D.	Chemical	Plant Production (10 ³ lb/yr)	Sequential Listing of All Vent Gas Treatment Devices	Process Vent Stream Characteristics ^c		
				Flow (scfm)	Heat Value (Btu/scf)	VOC (lb/hr)
HYD-1	Hexamethylene diamine	180	No Controls	70	323	6.6
HYD-2	Hexamethylene diamine	190	Boiler	(113)	(900)	0
HYD-3	Cyclohexane	1.6	-	NO	PROCESS	VENTS
HYD-5	Aniline	150	-	NO	PROCESS	VENTS
HYD-6	Butanediol	DMA	Flare	DMA	DMA	DMA
HYD-7	Cyclohexanol	DMA	-	NO	PROCESS	VENTS
HYD-8	Toluene Diamine	DMA	Incinerator	DMA	DMA	DMA
HYD-9	n-Butyl Alcohol	DMA	Flare	(3.2)	(1,578)	(19.6)
HYD-10	Hexamethylene Diamine	DMA	Boiler	(1,304)	(462)	(0)
HYD-11	p-Butylene	DMA	-	NO	PROCESS	VENTS
HYDC-3	Methyl Chloride	DMA	Scrubber/Condenser/Incinerator	DMA	DMA	DMA
HYDC-4	Methyl Chloride	80	Refrigerated Condenser	20	(Assume 500)	2.1
HYDC-5	Ethyl Chloride	DMA	-	NO	PROCESS	VENTS
HYDC-6	Methyl Chloride	100	Flare	(20)	(1,286)	(148)
HYDC-7	Ethyl Chloride	16	-	NO	PROCESS	VENTS
HYDC-8	Ethyl Chloride	DMA	-	NO	PROCESS	VENTS
HYDC-9	Ethyl Chloride	DMA	-	NO	PROCESS	VENTS
HYDC-10	Ethyl Chloride	DMA	-	NO	PROCESS	VENTS
HYDC-11	Ethyl Chloride	DMA	-	NO	PROCESS	VENTS
HYDC-12	Epichlorohydrin	250	Condenser/Incinerator Combustion Device	DMA	DMA	DMA
HYDF-1	Ono Alcohols	500	Condenser/Flare	DMA	DMA	DMA
HYDF-2	Butyraldehyde	175	Boiler	(729)	(1,233)	(2,394)
HYDI-1	Adiponitrile	180	M ₃ Scrubber	1,080	70	27
HYDO-1	Propylene Oxide	350	Condenser	99	0	0.1
HYDO-2	Sec Butyl Alcohol	270	Flare	DMA	DMA	DMA
HYDO-3	Glycerin	DMA	-	DMA	DMA	DMA
HYDR-1	Propylene Glycol	DMA	-	NO	PROCESS	VENTS
HYDR-2	Ethylene Glycol	183	-	NO	PROCESS	VENTS
HYDR-3	Ethylene Glycol	DMA	-	NO	PROCESS	VENTS
HYDR-4	Ethylene Glycol	DMA	-	NO	PROCESS	VENTS
MIT-1	Nitrobenzene	123	No Controls	13	404	19
MIT-2	Dinitrotoluene	88	VOC Scrubber	822	0	0.1
MIT-3	Dinitrotoluene	DMA	VOC Scrubber/Incinerator	DMA	DMA	DMA
MUT-1	Linear Alkylbenzene	250	-	NO	PROCESS	VENTS
MUT-2	Linear Alkylbenzene	DMA	-	NO	PROCESS	VENTS
MUT-3	Bodycylbenzene sulfonic acid, Sodium Salt	DMA	-	NO	PROCESS	VENTS

APPENDIX C. EMISSION DATA PROFILE (Cont Inued)

Unit Process I.D.	Chemical	Plant Production (10 ³ lb/yr)	Sequential Listing of All Vent Gas Treatment Devices	Process Vent Stream Characteristics ^c		
				Flow (scfm)	Heat Value (Btu/scf)	VOC (lb/hr)
OLIG-1	Octene	DMA	-	NO	REACTOR	PROCESS
OLIG-2	Dodecene	DMA	-	NO	REACTOR	VENTS
OLIG-3	n-Butylene	DMA	-	NO	REACTOR	PROCESS
OLIG-4	Tripropylene	DMA	-	NO	REACTOR	VENTS
OLIG-5	Dodecene	DMA	-	NO	REACTOR	PROCESS
OL-1	Adipic Acid	640	H ₂ O Scrubber	2,800	0	0
OL-2	Adipic Acid	100	No Controls	848	0	0
OL-3	Adipic Acid	700	H ₂ O Scrubber/Boller	(4,653)	(0)	(0)
OL-4	Ethylene Oxide	292	No Controls	12,187	4	130
OLTA-1	Vinyl Acetate	398	No Controls	7	487	0.1
OLTC-1	Ethylene Dichloride	912	Incinerator	(304)	(713)	(748)
PHO-1	Toluene Diisocyanate	DMA	-	NO	REACTOR	PROCESS
PYR-1	Ketene	300	-	NO	REACTOR	VENTS
PYR-2	Ethylene	DMA	-	NO	REACTOR	PROCESS
PYR-3	Ketene	600	-	NO	REACTOR	VENTS
PYR-4	Propylene	DMA	-	NO	REACTOR	PROCESS
PYR-5	Ethylene	DMA	-	NO	REACTOR	VENTS
PYR-6	Vinyl Chloride Monomer	310	-	NO	REACTOR	PROCESS
PYR-7	Bisvinyl	DMA	-	NO	REACTOR	VENTS
SUL-1	Dodecylbenzene sulfonic acid	30	Acid Gas Scrubber	1,863	0	0.1
SULP-1	Carbon Disulfide	DMA	-	NO	REACTOR	PROCESS
						VENTS

APPENDIX C (Concluded). FOOTNOTES

a. Process units are identified by the chemical reaction associated with their manufacture. Reaction codes are as follows:

ALK - Alkylation	HYD - Hydrogenation
AMH - Amination	HYDC - Hydrochlorination
AMH - Amination	HYDF - Hydroformylation
CAR - Carbonylation	HYDI - Hydrodimerization
CLE - Cleavage	HYDO - Hydrolysis
CRE - Catalytic Reforming	HYDR - Hydration
CHL - Chlorination	HIT - Nitration
CON - Condensation	NUT - Neutralization
DEHY - Dehydration	OLIG - Oligomerization
DEH - Dehydrogenation	OXI - Oxidation (Pure O ₂)
DEHC - Dehydrochlorination	OXYA - Oxyacetylation
EST - Esterification	OXYC - Oxychlorination (Pure O ₂)
ETH - Etherification	PHO - Phosgenation
ETHY - Ethynylation	PVR - Pyrolysis
FLU - Fluorination	SUL - Sulfonation
	SULP - Sulfurization (Vapor Phase)

b. This listing identifies all process vent stream treatment devices, including all combustion and noncombustion devices identified in the data base. Devices are not listed when (1) there is no process vent stream or (2) there is a vent but it is recycled within the process or is a feed to another process (e.g., a hydrogen feed steam). All devices are listed in the sequence in which they occur.

c. For process units where combustion devices are used, the vent stream characteristics presented are in parentheses and represent the vent stream characteristics just prior to the combustion device. For units without combustion devices, the vent stream characteristics presented represent the vent at its point of discharge to the atmosphere. These are the characteristics upon which the TRE calculation is based.

d. DMA - Data not available.

e. For all process units where combustion is currently used, i.e., baseline, all vent stream data are in parentheses.

f. Data expressed in units of lbs per 10⁶ lbs of production because sufficient information was not available to express VOC in lb/hr.

APPENDIX D
EMISSION MEASUREMENT

APPENDIX D

EMISSION MEASUREMENT

D.1 INTRODUCTION

The proposed reactor processes new source performance standard (NSPS) divides reactor process facilities into two groups. One group of facilities is required under the proposed standard to reduce VOC emissions by combusting them in an incinerator or a flare. Emissions must be reduced by 98 weight percent for flares or by 98 weight percent or to 20 ppmv (total volume concentration, by compound), whichever is less stringent, for incinerators. Standard measurement methods should be used to determine the VOC reduction. The second group of facilities is not required to reduce VOC emissions under the proposed standard. As discussed in Chapter 6, the two groups of facilities are distinguished by a cutoff level of total resource effectiveness (TRE). An index value of TRE can be associated with each reactor process vent stream for which the offgas characteristics of flowrate and individual VOC emission concentrations are known. The proposed standard would require that measurements be made to determine whether a source has a TRE index value above or below the cutoff level. In this case, measurements are needed to determine the flowrate and individual VOC emission concentrations. The net heating value of the reactor process vent stream is then calculated.

The purpose of this appendix is to discuss and present measurement methods acceptable for determination of VOC reduction efficiency and/or individual VOC emission concentrations.

D.1.1 VOC MEASUREMENT

Numerous methods exist for the measurement of organic emissions. Among these methods are continuous flame ionization analyzers (FIA) and gas chromatograph (GC) (EPA Reference Methods 25 and 18). Each method has advantages and disadvantages. Of the two procedures, GC has the distinct advantage of identifying and quantifying the individual compounds. However, GC systems are expensive; and determination of the column required and analysis of samples can be time consuming.

The FIA technique is the simplest procedure. However, the FIA responds differently to various organic compounds and can yield highly biased results depending upon the compounds involved. Another disadvantage of the FIA is that a separate methane measurement is required to determine nonmethane organics. Of course, the direct FIA procedure does not identify or quantify individual compounds.

Method 25 sampling and analysis provides a single nonmethane organic measurement on a carbon basis; this is convenient for establishing control device efficiencies on a consistent basis. However, Method 25 does not provide any qualitative or quantitative information on individual compounds present. For these determinations, Method 18 must be used.

D.1.2 EMISSION MEASUREMENT TESTS

No emission measurement tests were performed during data gathering for this proposed standard. All emission data were collected directly from existing industry emission records.

D.2 PERFORMANCE TEST METHODS

EPA Methods 18 and 25 are the recommended test procedures for determining control device efficiencies for reactor processes. However, Method 25 is likely to yield slightly lower calculated efficiencies than actually obtained. Method 25 can be expected to yield higher results than the Method 18 at the emission outlet when the outlet concentration is less than 100 ppm volume; therefore, at this time, Method 25 is particularly not recommended for performance tests to measure compliance with the 98 percent reduction provision of the proposed standard when the outlet emissions are expected to be below 100 ppm. EPA Methods 1, 1A, 2, 2A, 2C, and 2D are recommended for determination of stack flowrates.

In order to determine the stream net heating value for reactor process sources, both identification and quantification of the substances being emitted are necessary. Method 18 can be used to: (1) determine individual VOC emissions from the control device outlet, (2) determine individual VOC reduction efficiency of the control device, and (3) provide data required to determine whether a source has a TRE index value above or below the cutoff level specified in the proposed standard.

The costs associated with performing a control device efficiency test, a total outlet VOC concentration test, or a test to gather data to compute a TRE value will vary widely, depending on the resources available; but are estimated to be \$10,000 or \$15,000 per test.

APPENDIX E
LIST OF 173 SYNTHETIC ORGANIC CHEMICALS
BEING CONSIDERED FOR REGULATION

LIST OF 173 SYNTHETIC ORGANIC CHEMICALS
BEING CONSIDERED FOR REGULATION

Common Name	Chemical Name	CAS No.
Acetaldehyde	Acetaldehyde	75-07-0
Acetic acid	Acetic acid	64-19-7
(1) Acetic anhydride (2) Acetic oxide	Acetic acid, anhydride	108-24-7
(1) Acetone (2) Dimethyl ketone	2-Propanone	67-64-1
(1) Acetone cyanohydrin (2) 2-Methylactonitrile	2-Hydroxy-2-methylpropanenitrile	75-86-5
(1) Acetylene (2) Ethine	Ethyne	74-86-2
Acrylic acid	2-Propenoic acid	79-10-7
Acrylonitrile	2-Propenenitrile	107-13-1
Adipic acid	Hexanedioic acid	124-04-9
(1) Adiponitrile (2) 1,4-Dicyanobutane	Hexanedinitrile	111-69-3
Alcohols, C-11 or lower, mixtures	Alcohols, C-11 or lower, mixtures	-
Alcohols, C-12 or higher, mixtures	Alcohols, C-12 or higher, mixtures	-
Alcohols, C-12 or higher, unmixed	Alcohols, C-12 or higher, unmixed	-
Alkylbenzene	Dodecylbenzene, linear	123-01-3
(1) Allyl chloride (2) 3-Chloropropene	3-Chloro-1-propene	107-05-1
Amylene	2-Methyl-2-butene	513-35-9
Amylenes, mixed	2-Methylbutenes, mixed	-
(1) Aniline (2) Phenylamine	Benzenamine	62-53-3

Common Name	Chemical Name	CAS No.
Benzenesulfonic acid	Benzenesulfonic acid	98-11-3
Benzenesulfonic acid C ₁₀₋₁₆ -alkyl derivatives, sodium salts	Benzenesulfonic acid C ₁₀₋₁₆ -alkyl derivatives, sodium salts	68081-81-2
Benzol	Benzene	71-43-2
(1) Benzyl chloride (2) α -Chlorotoluene	(Chloromethyl) benzene	100-44-7
(1) Bisphenol A (2) 4,4'-Isopropylidenediphenol	4,4'-(1-Methylethylidene) bisphenol	80-05-7
(1) Bivinyll (2) Divinyll	1,3-Butadiene	106-99-0
(1) Brometone (2) Tribromo-t-butyl alcohol (3) Acetone-bromoform	1,1,1-Tribromo-2-methyl-2- propanol	76-08-4
Butadiene and butene fractions	Butadiene and butene fractions	-
n-Butane	Butane	106-97-8
1,4-Butanediol	1,4-Butanediol	110-63-4
Butanes, mixed	Butanes, mixed	-
n-Butyl acetate	Acetic acid, butyl ester	123-86-4
Butyl acrylate	2-Propenoic acid, butyl ester	141-32-2
n-Butyl alcohol	1-Butanol	71-36-3
sec-Butyl alcohol	2-Butanol	78-92-2
(1) tert-Butyl alcohol (2) t-Butanol	2-Methyl-2-propanol	75-65-0
Butylbenzyl phthalate	1,2-Benzenedicarboxylic acid butyl, phenylmethyl ester	85-58-7
Butyl Cellosolve ^R	2-Butoxyethanol	111-76-2

Common Name	Chemical Name	CAS No.
α -Butylene	1-Butene	106-98-9
(1) β -Butylene (2) pseudo-Butylene	2-Butene	25167-67-3
Butylenes (mixed)	Butenes, mixed	-
tert-Butyl hydroperoxide	1,1-Dimethylethyl hydroperoxide	75-91-2
2-Butyne-1,4-diol	2-Butyne-1,4-diol	110-65-6
Butyraldehyde	Butanal	123-72-8
Butyric anhydride	Butanoic acid, anhydride	106-31-0
Caprolactam	Hexahydro-2H-azepin-2-one	105-60-2
(1) Carbofic acid (2) Hydroxybenzene	Phenol	108-95-2
Carbon disulfide	Carbon disulfide	75-15-0
Carbon tetrachloride	Tetrachloromethane	56-23-5
Chloroacetic acid	Monochloroacetic acid	79-11-8
Chlorobenzene	Chlorobenzene	108-90-7
Chloroform	Trichloromethane	67-66-3
(1) p-Chloronitrobenzene (2) p-Nitrochlorobenzene	1-Chloro-4-nitrobenzene	100-00-5
Citric acid	2-Hydroxy-1,2,3-propanetricarboxylic acid	77-92-9
Cumene	(1-Methylethyl) benzene	98-82-8
Cumene hydroperoxide	1-Methyl-1-phenylethyl hydroperoxide	80-15-9
(1) Cyanuric chloride (2) 2,4,6-Trichloro-s-triazine	2,4,6-Trichloro-1,3,5-triazine	108-77-0

Common Name	Chemical Name	CAS No.
Cyclohexane	Hexahydrobenzene	110-82-7
Cyclohexane, oxidized	Cyclohexane, oxidized	68512-15-2
Cyclohexanol	(1) Hexalin (2) Hexahydrophenol	108-93-0
Cyclohexanone	Pimelic ketone	108-94-1
Cyclohexanone oxime	Cyclohexanone oxime	100-64-1
Diacetone alcohol	4-Hydroxy-4-methyl-2-pentanone	123-42-2
1,4-Dichlorobutene	1,4-Dichloro-2-butene	110-57-6
3,4-Dichloro-1-butene	3,4-Dichloro-1-butene	64037-54-3
(1) Diethanolamine (2) 2,2'-Aminodiethanol	2,2'-Iminobisethanol	111-42-2
Diethylbenzene	Diethylbenzene	25340-17-4
Diethylene glycol	2,2'-Oxybisethanol	111-46-6
Diisodecyl phthalate	1,2-Benzenedicarboxylic acid diisodecyl ester	26761-40-0
Dimethyldichlorosilane	Dichlorodimethylsilane	75-78-5
(1) Dimethyl terephthalate (2) Terephthalic acid, dimethyl ester (3) DMT	1,4-Benzenedicarboxylic acid dimethyl ester	120-61-6
2,4-(and 2,6)-dinitrotoluene	1-Methyl-2,4-dinitrobenzene (and 2-Methyl-1,3-dinitrobenzene)	121-14-2
(1) Dioctyl phthalate (2) Bis (2-ethylhexyl) phthalate (3) Di (2-ethyl hexyl) phthalate	1,2-Benzenedicarboxylic acid bis (2-ethylhexyl) ester	117-81-7

Common Name	Chemical Name	CAS No.
(1) Dodecene	1-Dodecene	25378-22-7
(2) Tetrapropylene		
Dodecylbenzene, non linear	Dodecylbenzene, non linear	123-01-2
Dodecylbenzenesulfonic acid	Dodecylbenzenesulfonic acid	1886-81-3
Dodecylbenzenesulfonic acid, sodium salt	Dodecylbenzenesulfonic acid, sodium salt	25155-30-0
Epichlorohydrin	(Chloromethyl) oxirane	106-89-8
Ethanolamine	2-Aminoethanol	141-43-5
Ethyl acetate	Acetic acid, ethyl ester	141-78-6
Ethyl acrylate	2-Propenoic acid, ethyl ester	140-88-5
Ethyl alcohol	Ethanol	64-17-5
Ethylbenzene	Ethylbenzene	100-41-4
Ethyl chloride	Chloroethane	75-00-3
(1) Ethylene	Ethene	74-85-1
(2) Elayl		
(3) Olefiant gas		
(1) Ethylene dibromide	1,2-Dibromoethane	106-93-4
(2) Ethylene bromide		
(1) Ethylene dichloride	1,2-Dichloroethane	107-06-2
(2) Ethylene chloride		
Ethylene glycol	1,2-Ethanediol	107-21-1
(1) Ethylene glycol monoethyl ether acetate	2-Ethoxyethyl acetate	111-15-9
(2) Cellosolve acetate ^R		
(1) Ethylene glycol monomethyl ether	2-Methoxyethanol	109-86-4
(2) Methyl Cellosolve ^R		

Common Name	Chemical Name	CAS No.
Ethylene oxide	Oxirane	75-21-8
2-Ethylhexyl alcohol	2-Ethyl-1-hexanol	104-76-7
(2-Ethylhexyl) amine	(2-Ethylhexyl) amine	104-75-6
6-Ethyl-1,2,3,4-tetrahydro 9,10-antracenedione	6-Ethyl-1,2,3,4-tetrahydro 9,10-antracenedione	15547-17-8
Formaldehyde	(1) Formalin (solution) (2) Methanal (gas)	50-00-0
(1) Freon 11 (2) Fluorotrichloromethane	Trichlorofluoromethane	75-69-4
Freon 12	Dichlorodifluoromethane	75-71-8
Freon 21	Dichlorofluoromethane	75-43-4
Freon 22	Chlorodifluoromethane	75-45-6
(1) Glycerol (2) Glyceryl (3) Glycerin	1,2,3-Propanetriol	56-81-5
n-Heptane	Heptane	142-82-5
Heptenes (mixed)	Heptenes (mixed)	-
Hexamethylene diamine	1,6-Hexanediamine	124-09-4
(1) Hexamethylene diamine adipate (2) Nylon salt	1,6-Hexanediamine adipate	3323-53-3
(1) Hexamine (2) Hexamethylene tetramine	1,3,5,7-Tetraazatricyclo (3.3.1.1 ^{3,7})-decane	100-97-0
Hexane	Hexane	110-54-3
Isobutane	2-Methylpropane	75-28-5
Isobutyl alcohol	2-Methyl-1-propanol	78-83-1

Common Name	Chemical Name	CAS No.
(1) Isobutylene (2) 2-Methylpropene	2-Methyl-1-propene	115-11-7
Isobutyraldehyde	2-Methylpropanal	78-84-2
Isopentane	2-Methylbutane	78-78-4
Isoprene	2-Methyl-1,3-butadiene	78-79-5
(1) Isopropyl acetone (2) Methyl Isobutyl ketone	4-Methyl-2-pentanone	108-10-1
Isopropyl alcohol	2-Propanol	67-63-0
Ketene	Ethenone	463-51-4
Linear alcohols, ethoxylated, mixed	Linear alcohols, ethoxylated, mixed	-
Linear alcohols, ethoxylated, and sulfated, sodium salt, mixed	Linear alcohols, ethoxylated, and sulfated, sodium salt, mixed	-
Maleic anhydride	2,5-Furandione	108-31-6
Mesityl oxide	4-Methyl-3-penten-2-one	141-79-7
(1) Methyl alcohol (2) Wood alcohol	Methanol	67-56-1
Methylamine	Methanamine	74-39-5
ar-Methylbenzenediamine	ar-Methylbenzenediamine	25376-45-8
Methyl chloride	Chloromethane	74-87-3
Methyl chloroform	1,1,1-Trichloroethane	71-55-6
Methylene chloride	Dichloromethane	75-09-2
Methyl ethyl ketone	2-Butanone	78-93-3
(1) Methyl methacrylate (2) Methacrylic acid methyl ester	2-Methyl-2-propenoic acid, methyl ester	80-62-6

Common Name	Chemical Name	CAS No.
1-Methyl-2-pyrrolidone	1-Methyl-2-pyrrolidinone	872-50-4
MTBE	Methyl tert-butyl ether	-
(1) Naphthene (2) Naphthalin	Naphthalene	91-20-3
Nitrobenzol	Nitrobenzene	98-95-3
(1) n-Nonanol (2) Nonyl alcohol	1-Nonanol	143-08-8
Nonylphenol	Nonylphenol	25154-52-3
Nonylphenol, ethoxylated	Nonylphenol, ethoxylated	9016-45-9
Octene	Octene	25377-83-7
Oil-soluble petroleum sulfonate, calcium salt	Oil-soluble petroleum sulfonate, calcium salt	-
Pentaerythritol	2,2-Bis (Hydroxymethyl)- 1,3-propanediol	115-77-5
3-Pentenitrile	3-Pentenitrile	4635-87-4
Pentenes, mixed	Pentenes, mixed	109-67-1
1-Phenylethyl hydroperoxide	1-Phenylethyl hydroperoxide	-
Phenylpropane	Propylbenzene	103-65-1
Phosgene	Carbonic dichloride	75-44-5
Phthalic anhydride	1,3-Isobenzofurandione	85-44-9
Propane	Dimethyl methane	74-98-6
Propionaldehyde	Propanal	123-38-6
Propyl alcohol	1-Propanol	71-23-8
Propylene	1-Propene	115-07-1

Common Name	Chemical Name	CAS No.
Propylene glycol	1,2-Propanediol	57-55-6
Propylene oxide	Methyloxirane	75-56-9
Sorbitol	D-Glucitol	50-70-4
Styrene	Ethenylbenzene	100-42-5
Terephthalic acid	1,4-Benzenedicarboxylic acid	100-21-0
(1) Tetrachloroethylene (2) Perchloroethylene	Tetrachloroethene	127-18-4
Tetraethyl lead	Tetraethylplumbane	78-00-2
1,2,3,4-Tetrahydrobenzene	Cyclohexene	110-83-8
Tetra (methyl-ethyl) lead	Tetra (methyl-ethyl) plumbane,	-
Tetramethyl lead	Tetramethylplumbane	75-74-1
THF	Tetrahydrofuran	109-99-9
Toluene	Methylbenzene	108-88-3
(1) Toluene-2,4-diamine (2) 2,4-Diaminotoluene (3) 2,4-Tolylenediamine	4-Methyl-1,3-benzenediamine	95-80-7
Toluene-2,4-(and, 2,6)- diisocyanate (80/20 mixture)	1,3-Diisocyanato-2-(and 4-) methylbenzene (80/20 mixture)	26471-62-5
Trichloroethylene	Trichloroethylene	79-01-6
(1) Trichlorotrifluoroethane (2) Flucrocarbon 113	1,1,2-Trichloro-1,2,2- trifluoroethane	76-13-1
(1) Triethanolamine (2) Triethylolamine	2,2',2"-Nitrilotrisethanol	102-71-6
Triethylene glycol	2,2'-(1,2-Ethanedylbis (oxy)) bisethanol	112-27-6
Trimethylene	Cyclopropane	75-19-4

Common Name	Chemical Name	CAS No.
Tripropylene	1-Nonene	27215-95-8
Vinyl acetate	Acetic acid, ethenyl ester	108-05-4
Vinyl chloride	Chloroethene	75-01-4
Vinylidene chloride	1,1-Dichloroethene	75-35-4
Vinyl trichloride	1,1,2-Trichloroethane	79-00-5
m-Xylene	1,3-Dimethylbenzene	108-38-3
o-Xylene	1,2-Dimethylbenzene	95-47-6
p-Xylene	1,4-Dimethylbenzene	106-42-3
Xylenes (mixed)	Dimethylbenzenes (mixed)	1330-20-7

APPENDIX F
THE EQUATION AND COEFFICIENT DEVELOPMENT
FOR THERMAL INCINERATORS AND FLARES

APPENDIX F: TRE EQUATION AND COEFFICIENT DEVELOPMENT FOR THERMAL INCINERATORS AND FLARES

F.1 INTRODUCTION

This appendix describes the development of the TRE index equations used in the proposed standards for reactor processes. These equations can be used to directly calculate the TRE index based on the vent stream flowrate (scm/min), heating value (MJ/scm), and VOC emission rate (kg/hr).

F.2 INCINERATOR TRE INDEX EQUATION

This section presents the method used to develop the incinerator TRE index equation and an example calculation of the incinerator TRE index.

F.2.1 Incinerator TRE Index Equation Development

The incinerator TRE index equation was developed in the following manner. First, an equation for total annualized cost was determined by combining the equations for each component of the annualized costs. The equations for each annualized cost component are shown in Docket Item No. II-B-62 and include annualized capital costs, supplemental gas costs, labor costs, electricity costs, quench water costs, scrubber water costs, neutralization costs, and heat recovery credits.

The equation for total annualized costs developed from the equations for each annualized cost component (Docket Item No. II-B-62) was divided by the amount of VOC removed and the reference cost effectiveness of \$2,500/Mg of VOC removed to generate the general TRE index equation. Collecting like terms results in an equation with the following form:

$$TRE = \frac{1}{E_{TOC} f (Y_s)^{0.5}} [a + b(Q_s)^{0.88} + c(Q_s) + d(Q_s)(H_T) + e(Q_s)^{0.88}(H_T)^{0.88}] +$$

where for a vent stream flowrate (scm/min) at a standard temperature of 20°C is greater than or equal to 14.2 scm/min:

TABLE F-1. REACTOR PROCESSES NSPS TRE COEFFICIENTS FOR VENT STREAMS CONTROLLED BY AN INCINERATOR

DESIGN CATEGORY A1. FOR HALOGENATED PROCESS VENT STREAMS, IF $0 \leq \text{NET HEATING VALUE (MJ/scm)} \leq 3.5$:

Q_s = Vent Stream Flowrate (scm/min)	a	b	c	d	e	f
$14.2 \leq Q_s \leq 18.8$	19.65559	0.27948	0.76683	-0.13173	0	0.01044
$18.8 \leq Q_s \leq 699$	20.48848	0.27948	0.30929	-0.13173	0	0.01044
$699 \leq Q_s \leq 1400$	40.83338	0.30372	0.30929	-0.13173	0	0.01477
$1400 \leq Q_s \leq 2100$	61.17828	0.31887	0.30929	-0.13173	0	0.01809
$2100 \leq Q_s \leq 2800$	81.52318	0.33007	0.30929	-0.13173	0	0.02088
$2800 \leq Q_s \leq 3500$	101.86808	0.33902	0.30929	-0.13173	0	0.02335

DESIGN CATEGORY A2. FOR HALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE > 3.5 MJ/scm:

Q_s = Vent Stream Flowrate (scm/min)	a	b	c	d	e	f
$14.2 \leq Q_s \leq 18.8$	19.31203	0.27099	0.20500	0	0	0.01044
$18.8 \leq Q_s \leq 699$	20.14491	0.27099	-0.25255	0	0	0.01044
$699 \leq Q_s \leq 1400$	40.14625	0.29449	-0.25255	0	0	0.01477
$1400 \leq Q_s \leq 2100$	60.14759	0.30917	-0.25255	0	0	0.01809
$2100 \leq Q_s \leq 2800$	80.14892	0.32003	-0.25255	0	0	0.02088
$2800 \leq Q_s \leq 3500$	100.15028	0.32872	-0.25255	0	0	0.02335

DESIGN CATEGORY B. FOR NONHALOGENATED PROCESS VENT STREAMS, IF $0 \leq \text{NET HEATING VALUE (MJ/scm)} \leq 0.48$:

Q_s = Vent Stream Flowrate (scm/min)	a	b	c	d	e	f
$14.2 \leq Q_s \leq 1340$	8.84812	0.10696	0.09188	-0.17252	0	0.01044
$1340 \leq Q_s \leq 2690$	17.55267	0.11623	0.09188	-0.17252	0	0.01477
$2690 \leq Q_s \leq 4040$	26.25721	0.12203	0.09188	-0.17252	0	0.01809

DESIGN CATEGORY C. FOR NONHALOGENATED PROCESS VENT STREAMS, IF $0.48 < \text{NET HEATING VALUE (MJ/scm)} \leq 1.9$:

Q_s = Vent Stream Flowrate (scm/min)	a	b	c	d	e	f
$14.2 \leq Q_s \leq 1340$	9.56783	0.06187	0.32303	-0.16316	0	0.01044
$1340 \leq Q_s \leq 2690$	18.99209	0.06723	0.32303	-0.16316	0	0.01477
$2690 \leq Q_s \leq 4040$	28.41635	0.07058	0.32303	-0.16316	0	0.01809

DESIGN CATEGORY D. FOR NONHALOGENATED PROCESS VENT STREAMS, IF $1.9 < \text{NET HEATING VALUE (MJ/scm)} \leq 3.6$:

Q_s = Vent Stream Flowrate (scm/min)	a	b	c	d	e	f
$14.2 \leq Q_s \leq 1180$	6.87612	0.07036	0.02669	0	0	0.01044
$1180 \leq Q_s \leq 2370$	13.60866	0.07646	0.02669	0	0	0.01477
$2370 \leq Q_s \leq 3550$	20.34120	0.08028	0.02669	0	0	0.01809

DESIGN CATEGORY E. FOR NONHALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE > 3.6 MJ/scm:

Y_s = Dilution Flowrate (scm/min) = $(Q_s)(N_T)/3.6$	a	b	c	d	e	f
$14.2 \leq Y_s \leq 1180$	6.87612	0	0	0.00730	0.02249	0.01044
$1180 \leq Y_s \leq 2370$	13.60866	0	0	0.00730	0.02445	0.01477
$2370 \leq Y_s \leq 3550$	20.34120	0	0	0.00730	0.02566	0.01809

TRE = Total resource effectiveness index value.

Q_s = Vent stream flowrate (scm/min), at a standard temperature of 20°C.

H_T = Vent stream net heating value (MJ/scm), where the net enthalpy per mole of vent stream is based on combustion at 25°C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20°C, as in the definition of Q_s .

E_{TOC} = Hourly emissions of total organic compounds reported in kg/hr measured at full operating flowrate.

$Y_s = Q_s$ for all vent stream categories listed in Table F-1 except for Category E vent streams where $Y_s = (Q_s)(H_T)/3.6$.

where for a vent stream flowrate (scm/min) at a standard temperature of 20°C that is less than 14.2 scm/min:

TRE = Total resource effectiveness index value.

$Q_s = 14.2$ scm/min

$H_T = (FLOW)(HVAL)/14.2$

where:

FLOW = Vent stream flowrate (scm/min), at a temperature of 20°C.

HVAL = Vent stream net heating value (MJ/scm), where the net enthalpy per mole of vent stream is based on combustion at 25°C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20°C, as in the definition of Q_s .

E_{TOC} = Hourly emissions of total organic compounds reported in Kg/hr measured at full operating flowrate.

$Y_s = Q_s$ for all vent stream categories listed in Table F-1 except for Category E vent streams where $Y_s = (Q_s)(H_T)/3.6$.

The coefficients a through f are functions of incinerator design parameters, such as temperature, residence time, supplemental fuel requirements, etc. As discussed in Chapter 8, there are six different design categories of incinerators. The design parameters were previously

presented in Table 8-1. Substituting the design values from Table 8-1 into the general equation allows values for coefficients a through f to be derived for each design category. This derivation is included in Docket Item No. II-B-62.

The results of this derivation are summarized in Table F-1. As shown, the coefficients are divided into six incinerator design categories. Under each design category listed in Table F-1, there are several intervals of vent stream flowrate. Each flowrate interval is associated with a different set of coefficients. The first flowrate interval in each design category applies to vent streams with a flowrate corresponding to the smallest control equipment system easily available without special custom design.

The remaining flowrate intervals in each design category apply to vent streams which would be expected to use two, three, four, or five sets of control equipment, respectively. These flowrate intervals are distinguished from one another because of limits to prefabricated equipment sizes. The flowrate intervals and maximum vent stream flowrate for each design category are discussed in Chapter 8.

F.2.2 Example Calculation of an Incinerator-based TRE Index Value for a Facility

This section presents an example of use of the TRE index equation. The example reactor process vent stream has the following characteristics:

1. Q_s = 284 scm/min
2. H_T = 0.37 MJ/scm
3. E_{TOC} = 76.1 kg/hr.
4. Y_s = 284 scm/min.
5. No halogenated compounds in the vent stream.

Based on the stream heating value of 0.37 MJ/scm, Category B is the applicable incinerator design category for this stream. The flowrate is 284 scm/min, and therefore the coefficients for the second flowrate interval under Category B are used. The coefficients for Category B, flow interval #1 are:

$$a = 8.85$$

$$b = 0.107$$

$$c = 0.092$$

$$d = -0.173$$

$$e = 0$$

$$f = 0.010$$

The TRE equation is:

$$TRE = \frac{1}{E_{TOC}} [a + b(Q_s)^{0.88} + c(Q_s) + d(Q_s)(H_T) + e(Q_s)^{0.88}(H_T)^{0.88} + f(Q_s)^{0.5}]$$

$$TRE = (.013)[8.85 + 0.107 (284)^{0.88} + (0.092)(284) - 0.173 (284)(.37) + 0 + 0.010(284)^{0.5}]$$

$$TRE = 0.116 + 0.203 + 0.343 - 0.239 + 0 + 0.002$$

$$TRE = 0.425$$

Since the calculated TRE index value of 0.425 is less than the cutoff value of 1.0, this facility would be required to reduce VOC emissions by 98 weight-percent or to 20 ppmv because the cost of incineration is considered to be reasonable. Because the TRE index is a ratio of two cost-effectiveness values, it is possible to calculate cost effectiveness for controlling any vent stream given its TRE index value. The TRE index value of the facility is multiplied by the reference cost-effectiveness \$2,500/Mg as follows:

$$TRE = 0.425$$

$$\text{Reference cost effectiveness} = \$2,500/\text{Mg}$$

$$\text{Cost effectiveness for example stream} = (0.425)(2,500) = \$1,063/\text{Mg of VOC removed}$$

If the TRE index value for this example were above 1.0, the flare-based TRE equation (see Section F.3) would be used to calculate the flare-based TRE index because flares can be applied to nonhalogenated vent streams. If the flare-based TRE index were less than 1.0, this facility would have to reduce VOC emissions by 98 weight-percent or to 20 ppmv, whichever is less stringent. If the flare TRE index were also above 1.0, or if the stream contained halogenated compounds so a flare could not be used, then no further controls would be required.

F.3 FLARE SYSTEM TRE DEVELOPMENT

This section presents the development of the flare TRE index equation, verification of the equation, and an example calculation of the flare TRE index.

F.3.1 Development of the Flare TRE Index Equation

The flare TRE index equation was developed by selecting a general form for the equation which contained the stream characteristics of flowrate, heating value, and VOC emission rate as the independent variables, and the TRE index as the dependent variable, and fitting this equation to TRE index values calculated from the annualized cost equations. The form of the TRE index equation for flaring had to be selected so that an accurate prediction of the TRE index could be obtained for a given set of vent stream characteristics. The form of the flare TRE index equation selected was the same as the form used in the proposed standards for Distillation Operations (50 FR 20446). An identical form of the TRE index equation was adopted for the reactor standards from the distillation standards because the VOC control costing procedures for the two standards are similar. The TRE index equation was a good predictor of the TRE index for the distillation standards. Therefore, it was expected that the same equation would also be applicable for the reactor standards.

The general form of the equation is as follows:

$$TRE = \frac{1}{E_{TOC}} [a(Q_s) + b(Q_s)^{0.8} + c(Q_s)(H_T) + d(E_{TOC}) + e]$$

where:

TRE = total resource effectiveness index value

Q_s = vent stream flowrate (scm/min) at a standard temperature of 20°C

H_T = vent stream net heating value (MJ/scm) where the net enthalpy per mole of vent stream is based on combustion at 25°C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20°C as in the definition of Q_s .

E_{TOC} = hourly emission rate of total organic compounds reported in kg/hr measured at full operating flowrate.

a, b, c, d, and e are coefficients.

The coefficients for the flare TRE index equation were developed with the same regression analysis procedure that was used to develop the flare TRE coefficients in the distillation standards. The regression analysis procedure used is the General Linear Model (GLM) procedure of the Statistical Analysis System Institute, Inc., Raleigh, North Carolina. The development of the coefficients involved three steps: (1) formation of an appropriate data base for the regression; (2) calculating a TRE index value for each set of vent stream characteristics in the data base with the flare costing procedure described in Chapter 8; and (3) using the GLM procedure to regress TRE index values against the vent stream characteristics.

It was infeasible to use only the reactor processes Emissions Data Profile (EDP) as the data base for the regression analysis because the EDP is too small for the analysis that had to be performed. Therefore, the distillation NSPS National Emissions Profile (NEP) was used as the supplement to the reactor processes EDP for the purposes of the analysis. Adding the distillation NEP was judged to be appropriate because of two significant similarities with the reactor processes EDP: (1) the vent stream characteristics represented in the two data bases are similar; and (2) identical or similar synthetic organic chemicals are produced by both reactor processes and distillation operations.

After the data base was formed, the cost of controlling VOC emissions using flares was calculated from the annualized cost equations for each

facility with nonhalogenated vent streams in the EDP and NEP. These costs were divided by the amount of VOC emissions reduced by flaring (i.e., 98 weight-percent) to obtain a value for cost of control per megagram of VOC reduced. Next, these values were divided by a TRE cutoff of \$2,500/Mg to obtain a TRE index value for each facility. The TRE index value and vent stream characteristics for each facility were then input to the GLM regression program.

Coefficients were developed for each term in the TRE equation using the TRE index value as the dependent variable and the vent stream characteristics as independent variables. The flare TRE coefficients are shown in Table F-2. A set of coefficients was developed for each of two cases: (1) combustion with a flare for vent streams with heating values below 11.2 MJ/scm (300 Btu/scf), and (2) combustion with a flare for vent streams with heating values at or above 11.2 MJ/scm (300 Btu/scf). The first set of coefficients include the natural gas cost incurred by facilities with vent stream heating values below 11.2 MJ/scm (300 Btu/scf). For this type of stream, enriching with natural gas to reach 11.2 MJ/scm (300 Btu/scf) is necessary to ensure a 98 weight-percent reduction efficiency of VOC. No enriching is necessary for facilities with vent stream heating values at or above 11.2 MJ/scm (300 Btu/scf). Therefore a second set of TRE coefficients was developed for streams with heating values at or above 11.2 MJ/scm.

F.3.2 Flare TRE Coefficients Verification

The flare TRE equation and coefficients were examined to ensure their capability of accurately predicting the TRE index value for a facility from the vent stream characteristics. The verification procedure for the flare TRE coefficients involved several steps: (1) calculation of a TRE index value using the newly derived TRE equation for each facility in the data base; (2) calculation of a TRE index value using the flare cost algorithm described in Chapter 8 for each facility in the data base; and (3) comparison of the TRE index values from (1) and (2) through the calculation of percent difference. The verification procedure focused on those cases where the TRE index value is around 1.0 because it is important to have the most accurate

TABLE F-2. REACTOR PROCESSES NSPS TRE COEFFICIENTS FOR VENT STREAMS
CONTROLLED BY A FLARE

	a	b	c	d	e
Flare $H_T < 11.2 \text{ MJ/scm}$	2.25	0.288	-0.193	-0.0051	2.08
Flare $H_T \geq 11.2 \text{ MJ/scm}$	0.309	0.0619	-0.0043	-0.0034	2.08

predictive capabilities in this critical region. The results of the verification procedure are discussed below.

For vent streams with heating values at or above 11.2 MJ/scm, the percent difference in TRE index values near the cutoff range from -0.49 to 3.39. Thus, it was concluded that the coefficients for this category of vent streams provide good agreement with the actual TRE index values. Table F-3 presents a comparison of TRE indexes near the cutoff for vent streams with heating values at or above 11.2 MJ/scm. The comparison is between TRE index values calculated with the TRE equation and those calculated using the cost algorithm for the same facility as described above.

For vent streams with heating values below 11.2 MJ/scm there was poor agreement initially between the algorithm and TRE equation. Therefore, those data points resulting in very high TRE indexes were removed after the initial verification procedure was performed because they caused the poor agreement at TRE index values near the cutoff. After removal of those data points, the TRE coefficients for vent stream heating values less than 11.2 MJ/scm were recalculated and the verification procedure was undertaken again. The percentage difference in the recalculated TRE index values near the cutoff ranged from 2.38 to -7.39. Thus, it was concluded that the recalculated TRE coefficients for vent streams with heating values below 11.2 MJ/scm provided good agreement with the actual TRE index values. Table F-4 presents a comparison of TRE indexes near the cutoff for vent streams with heating values below 11.2 MJ/scm.

As a final verification step for vent streams with heating values below 11.2 MJ/scm, the recalculated TRE coefficients were used to determine a TRE index value for those data points which were removed after the initial verification procedure was performed. The percentage difference between the TRE index values determined using the recalculated coefficients and the TRE index values determined using the flare cost algorithm ranged from 2.29 to -6.24. Thus, it was concluded that the coefficients enable accurate estimation of even those facilities with high TRE index values. Table F-5 presents a comparison of TRE index values for those vent streams with high TRE index values.

TABLE F-3. TRE INDEX VALUES GENERATED USING TRE COEFFICIENTS AND THE FLARE COST ALGORITHM NET HEATING VALUE GREATER THAN OR EQUAL TO 300 Btu/scf

Flowrate (scf/min)	Heat Content (Btu/scf)	VOC (lb/hr)	TRE INDEX VALUE Algorithm Coefficients	Percent Difference
70.00	323.00	6.60	0.88 0.91	3.39
1.45	903.00	1.60	2.90 2.91	0.43
1.20	1024.00	3.81	1.22 1.22	0.03
2.04	1024.00	6.47	0.72 0.72	-.08
1.39	966.00	6.04	0.77 0.77	-.06
.20	2778.00	2.00	2.31 2.31	-.01
0.30	4978.00	4.90	0.95 0.94	-.49
6.60	1286.00	3.00	1.57 1.57	0.08

TABLE F-4. PERCENT DIFFERENCE BETWEEN TRE INDEX VALUES GENERATED USING THE EQUATION AND THE FLARE COST ALGORITHM NET HEATING VALUE LESS THAN 300 Btu/scf

Flowrate (scf/min)	Heat Content (Btu/scf)	VOC (lb/hr)	TRE INDEX VALUES		Percent Differences Compared to Algorithm Coefficients Recalculated ^a
			Algorithm	Coefficients Recalculated	
17.00	181.00	16.00	0.38	.37	-2.23
75.00	102.00	6.10	2.12	2.12	0.00
50.40	70.00	16.90	0.65	0.65	0.00
4.40	190.00	4.00	1.22	1.24	1.84
22.60	92.00	10.50	0.73	0.69	-5.16
11.30	168.00	5.23	1.16	1.07	-7.39
68.70	72.00	26.30	0.50	0.50	0.21
7.57	18.00	5.00	1.14	1.16	2.06
27.30	47.00	8.50	1.02	0.99	-3.63
4.20	18.00	28.50	1.04	1.06	1.29
88.00	47.00	2.50	0.57	.58	0.68
7.50	47.00	4.00	2.23	2.28	2.38
2.40	260.00	4.00	1.17	1.18	1.05
17.90	69.00	8.00	0.92	0.87	-5.71
15.00	149.00	6.60	0.96	0.91	-5.29
80.00	9.00	19.60	0.87	0.86	-1.53

^aTRE coefficients derived from vent streams with a heating value greater than 40 Btu/scf but less than 300 Btu/scf.

TABLE F-5. PERCENT DIFFERENCES BETWEEN TRE INDEX VALUES GENERATED BY THE COST ALGORITHM AND THE TRE EQUATION FOR VENT STREAMS WITH HEATING VALUES LESS THAN 40 Btu/scf

Flowrate (scf/min)	Heat Content (Btu/scf)	VOC (lb/hr)	TRE INDEX VALUE Algorithm Coefficients ^a		Percent Difference
99.00	0.00	0.10	203	202	-.91
822.00	0.00	0.10	1325	1290	-2.65
16.67	4.00	.37	21	20	-5.16
0.05	36.00	0.10	46	46	0.19
39.20	4.00	0.18	61	60	-2.28
6.60	8.00	.60	9	9	2.24
2.00	0.00	.003	1640	1658	1.14
6.25	9.00	.40	14	14	2.29
12.40	0.00	0.14	51	48	-6.24
13.53	0.00	0.03	242	228	-5.96

^aEquation coefficients were developed after excluding vent streams with heating values less than 40 Btu/scf.

In summary, the flare TRE equations developed for this NSPS allow for the calculation of TRE index values that are highly correlated with the TRE index values obtained from the costing algorithm. The TRE equations do not necessarily result in the best statistical fit between TRE values and vent stream characteristics. This is because the primary concern in developing the equation and coefficients is to ensure very good agreement between the TRE equation and cost algorithm for TRE's at or around the cutoff.

F.3.3 Example Calculation of a Flare-Based TRE Index Value for a Facility

This section presents an example calculation for the same vent stream used in Section F.2.2. The vent stream characteristics are as follows:

1. $Q_s = 284 \text{ scm/min}$
2. $H_T = 0.37 \text{ MJ/scm}$
3. $E_{TOC} = 76.1 \text{ kg/hr}$
4. No halogenated compounds in vent stream.

Based on the stream heating value of 0.37 MJ/scm, the coefficients for this stream are as follows:

- a = 2.25
- b = 0.288
- c = -0.193
- d = -0.0051
- e = 2.08

Substituting these values into the general TRE index equation gives the following result:

$$\text{TRE} = 0.013[2.25(284) + 0.288(284)^{0.8} - 0.193(284)(0.37) - 0.0051(76.1) + 2.08]$$
$$\text{TRE} = 8.41$$

This index is above the cutoff of 1.0. However, as previously shown in Section F.2.2, the TRE index for an incinerator applied to this stream was below 1.0. Therefore, this facility would be required to reduce VOC emissions by 98 weight-percent or below 20 ppmv.

APPENDIX G

FEDERAL REGISTER NOTICES OF ORGANIC
COMPOUNDS DETERMINED TO HAVE NEGLIGIBLE
PHOTOCHEMICAL REACTIVITY

APPENDIX G: FEDERAL REGISTER NOTICES OF ORGANIC
COMPOUNDS DETERMINED TO HAVE NEGLIGIBLE
PHOTOCHEMICAL REACTIVITY

INTRODUCTION

As indicated by Federal Register notices included in this appendix, the following chemicals have been determined to be negligibly photochemically reactive compounds: methane; ethane; 1,1,1-trichloroethane; methylene chloride, trichlorofluoromethane; dichlorodifluoromethane; chlorodifluoromethane; trifluoromethane; trichlorotrifluoroethane; dichlorotetrfluoroethane; and chloropentafluoroethane.

ENVIRONMENTAL PROTECTION AGENCY

(FRL 735-4)

AIR QUALITY

Recommended Policy on Control of Volatile Organic Compounds

PURPOSE

The purpose of this notice is to recommend a policy for States to follow on the control of volatile organic compounds (VOC), which are a constituent in the formation of photochemical oxidants (smog). This notice does not place any requirements on States: State Implementation Plan (SIP) provisions which offer reasonable alternatives to this policy will be approvable. However, this policy will be followed by EPA whenever it is required to draft State Implementation Plans for the control of photochemical oxidants.

BACKGROUND

Photochemical oxidants result from sunlight acting on volatile organic compounds (VOC) and oxides of nitrogen. Some VOC, by their nature, start to form oxidant after only a short period of irradiation in the atmosphere. Other VOC may undergo irradiation for a longer period before they yield measurable oxidant.

In its guidance to States for the preparation, adoption, and submittal of State Implementation Plans published in 1971, the Environmental Protection Agency emphasized reduction of total organic compound emissions, rather than substitution. (See 46 CFR Part 31, Appendix B.) However, in Appendix B, EPA stated that substitution of one compound for another might be useful where it would result in a clearly evident decrease in reactivity and thus tend to reduce photochemical oxidant formation. Subsequently, many State Implementation Plans were promulgated with solvent substitution provisions similar to Rule 66 of the Los Angeles County Air Pollution Control District. These regulations allowed exemptions for many organic solvents which have now been shown to generate significant photochemical oxidant.

On January 29, 1976, EPA published its "Policy Statement on Use of the Concept of Photochemical Reactivity of Organic Compounds in State Implementation Plans for Oxidant Control." The notice of availability of this document appeared in the *Federal Register* on February 5, 1976 (41 FR 3350).

The 1976 policy statement emphasized that the reactivity concept was useful as an interim measure only, and would not be considered a reduction in organic emissions for purposes of estimating attainment of the ambient air quality standard for oxidants. The document also included the following statement:

Although the substitution portions of Rule 66 and similar rules represent a workable and acceptable program at the present time, better substitution regulations can be developed, based on current knowledge of re-

activity and industrial capability. EPA in collaboration with State and industry representatives will formulate in 1978 an improved rule for national use.

SUMMARY

Analysis of available data and information show that very few volatile organic compounds are of such low photochemical reactivity that they can be ignored in oxidant control programs. For this reason, EPA's recommended policy reiterates the need for positive reduction techniques (such as the reduction of volatile organic compounds in surface coatings, process changes, and the use of control equipment) rather than the substitution of compounds of low (slow) reactivity in the place of more highly (fast) reactive compounds. There are three reasons for this. First, many of the VOC that previously have been designated as having low reactivity are now known to be moderately or highly reactive in urban atmospheres. Second, even compounds that are presently known to have low reactivity can form appreciable amounts of oxidant under multiday stagnation conditions such as occur during summer in many areas. Third, some compounds of low or negligible reactivity may have other deleterious effects.

Of the small number of VOC which have only negligible photochemical reactivity, several (benzene, acetonitrile, chloroform, carbon tetrachloride, ethylene dichloride, ethylene dibromide, and methylene chloride) have been identified or implicated as being carcinogenic, mutagenic, or teratogenic. An additional compound, benzaldehyde, while producing no appreciable ozone, nevertheless, forms a strong eye irritant under irradiation. In view of these circumstances, it would be inappropriate for EPA to encourage or support increased utilization of these compounds. Therefore, they are not recommended for exclusion from control. Only the four compounds listed in Table 1 are recommended for exclusion from SIP regulations and, therefore, it is not necessary that they be inventoried or controlled. In determining reductions required to meet oxidant NAAQS, these VOC should not be included in the base line nor should reductions in their emission be credited toward achievement of the NAAQS.

It is recognized that the two halogenated compounds listed in Table 1 (methyl chloroform and Freon 113) may cause deterioration of the earth's ultraviolet radiation shield since they are nearly unreactive in the lower atmosphere and all contain appreciable fractions of chlorine. The Agency has reached conclusions on the effects of only the fully halogenated chlorofluoroalkanes. The Agency on May 13, 1977 (42 FR 24342), proposed rules under the Toxic Substances Control Act (TSCA) to prohibit the nonessential use of fully halogenated chlorofluoroalkanes as aerosol propellants. The restrictions were applied to all members of this class, including Freon 113, since they are potential substitutes for Freon 11, Freon 12,

Freon 114, and Freon 115, which are currently used as aerosol propellants. The Agency is planning to investigate control systems and substitutes for nonpropellant uses under TSCA, as announced on May 13. Methyl chloroform is not a fully halogenated chlorofluoroalkane. Rather, it is among the chlorine-containing compounds for which the Agency has not completed its analysis; EPA has not yet concluded whether it is or is not a threat to the stratospheric ozone. Therefore, it has been placed on this list as an acceptable exempt compound. As new information becomes available on these compounds, EPA will reconsider the recommendation.

The volatile organic compounds listed in Table 2, while more photochemically reactive than those in Table 1, nevertheless do not contribute large quantities of oxidant under many atmospheric conditions.

TABLE 1.—Volatile Organic Compounds of Negligible Photochemical Reactivity That Should Be Exempt From Regulation Under State Implementation Plans

Methane
Ethane
1,1,1-Trichloroethane (Methyl Chloroform)
Trichlorofluoroethane (Freon 113)

These compounds have been implicated as having deleterious effects on stratospheric ozone and, therefore, may be subject to future controls.

TABLE 2.—Volatile Organic Compounds of Low Photochemical Reactivity

Propane
Acetone
Methyl Ethyl Ketone
Methanol
Isopropanol
Methyl Benzenes
Tertiary Alkyl Alcohols
Methyl Acetate
Phenyl Acetate
Ethyl Amines
Acrylonitrile
N, N-Dimethyl formamide

Only during multiday stagnations do Table 2 VOC yield significant oxidants. Therefore, if resources are limited or if the sources are located in areas where prolonged atmospheric stagnations are uncommon, priority should be given to controlling more reactive VOC first and Table 2 organics later. Table 2 VOC are to be included in base line emission inventories and reductions in them will be credited toward achievement of the NAAQS. Reasonably available control technology should be applied to significant sources of Table 2 VOC where necessary to attain the NAAQS for oxidants. New sources of these compounds will also be subject to new source review requirements.

Perchloroethylene, the principal solvent employed in the dry cleaning industry, is also of low reactivity, comparable to VOC listed in Table 2. It was not included in Table 2 because of reported adverse health effects. Uses, environmental distribution, and effects of perchloroethylene currently are being studied intensively by occupational health authorities. Currently are being studied investigations may have major impact on

industrial users. In designing control regulations for perchloroethylene sources, particularly dry cleaners, consideration should be given to these findings as well as industry requirements and the cost of applying controls. Available control technology is highly cost effective for large perchloroethylene dry cleaning operations. However, for coin-operated and small dry cleaners, the same equipment would represent a heavy economic burden.

As part of its continuing program, EPA will review new information relative to the photochemical reactivity, toxicity, or effects on stratospheric ozone of volatile organic compounds. Where appropriate, additions or deletions will be made to the lists of VOC in Tables 1 and 2.

Discussion

Most air pollution control regulations applicable to stationary sources of VOC in the United States are patterned after Rule 66 of the Los Angeles County Air Pollution Control District (presently Regulation 442 of the Southern California Air Pollution Control District). Rule 66 and similar regulations incorporate two basic strategies to reduce ambient oxidant levels, i.e., positive VOC reduction and selective solvent substitution based on photochemical reactivity. Positive reduction schemes such as incineration, absorption, and the use of low-solvent coatings are acknowledged means of reducing ambient oxidant levels; they should be retained in future VOC control programs. In contrast, the utility of solvent substitution strategies has been questioned as more information on photochemical reactivity has emerged.

EPA acknowledged the shortcomings of solvent substitution based on Rule 66 reactivity criteria in a 1976 policy statement (41 FR 5350). Findings were cited which indicated that almost all VOC eventually react in the atmosphere to form some oxidant. Concurrently, EPA initiated an investigation to consider implications of revising the solvent substitution aspects of Rule 66. Three separate forms were conducted with representatives of State and local air pollution control agencies, university professors, and industrial representatives with knowledge and expertise in the fields of atmospheric chemistry and industrial solvent applications. In addition, numerous discussions were held with acknowledged experts in the field. Topics of particular concern were:

Whether Rule 66 substitution criteria could be revised consistent with available reactivity data and yet be compatible with industrial processes and with product requirements.

Whether some compounds are of sufficiently low reactivity that they are not oxidant precursors and can be exempted from control under State Implementation Plans.

Whether the imposition of reactivity restrictions in addition to positive emission reductions will delay the development or implementation of promising technologies, particularly the use of water-borne and high-solids surface coatings.

Investigation showed that:

1. Solvent substitution based on Rule 66 has been directionally correct in the aggregate and probably effects some reductions in peak oxidant levels. However, because of the relatively high reactivity of most of the substituted solvents, the reduction is small compared to that which can be accomplished with positive reduction techniques. Revision of Rule 66 consistent with current knowledge of reactivity would eliminate the solvent substitution option for most sources in which substitution is now employed. Many of the organic solvents which have been categorized as having low photochemical reactivity are, in fact, moderately or highly reactive; they yield significant oxidant when subjected to irradiation in smog chambers designed to simulate the urban atmosphere.

2. A few VOC yield only negligible ozone when irradiated in smog chambers under both urban and rural conditions. Experiments conducted to date indicate that only methane and ethane, a group of halogenated paraffins, and three other organics—benzene, benzaldehyde, and acetonitrile—can be so classified. These compounds react very slowly yielding little ozone during the first few days following their release to the atmosphere. Available data suggest that none of the listed compounds contribute significant oxidant even during extended irradiation under multiday stagnation conditions.

The broad group "halogenated paraffins" includes important industrial solvents, most of which are chlorinated methanes and ethanes and chlorofluoroethanes. They find use as metal cleaning and dry cleaning solvents and as paint removers. Halogenated paraffins also serve as building blocks in the manufacture of other halogenated organics; these processes do not necessarily release significant VOC to the atmosphere.

3. Besides focusing on VOC of negligible reactivity, smog chamber studies show that a few additional VOC generate oxidant at a relatively slow rate. Under favorable atmospheric conditions, these VOC releases may not form oxidant until they have been transported substantial distances and become greatly diluted. However, under multiday stagnation conditions such as occur during summer in many areas of the middle and eastern United States, there is the potential for these organics to undergo appreciable conversion to oxidant. The more important VOC in this category are acetone, methyl ethyl ketone, perchloroethylene, methanol, isopropanol, and propane. All except propane are industrial solvents. The latter, a gas under normal conditions, is associated principally with crude oil and liquefied petroleum gas operations.

4. The vast number of volatile organic compounds—particularly nonhalogenated VOC—yield appreciable ozone when irradiated in the presence of oxides of nitrogen. While there are measurable variations in their rates of ozone formation, all are significantly more reactive than VOC listed in Table 2. Quickly reactive VOC include almost all aliphatic

and aromatic solvents, alcohols, ketones, glycols, and ethers.

5. Low photochemical reactivity is not synonymous with low biological activity. Some of the negligible or slowly reactive compounds have adverse effects on human health. Benzene, acetonitrile, carbon tetrachloride, chloroform, perchloroethylene, ethylene dichloride, ethylene dibromide, and methylene chloride have been implicated as being carcinogens, teratogens, or mutagens. In addition, benzaldehyde, which produces no appreciable ozone, nevertheless forms a strong eye irritant under irradiation. While their use might reduce ambient oxidant levels, it would be unwise to encourage their uncontrolled release. Additional halogenated organics are being investigated for possible toxicity.

Most of the related health information available at this time concerns acute toxicity. Threshold limit values (TLVs) have been developed for many VOC. They are appropriate for the healthy, adult work force exposed eight hours a day, five days a week. Experts suggest that more stringent levels should be established for the general population. Hazards represented by chronic and subchronic exposure are much more difficult to quantify than acute toxicity. Adverse health effects of the VOC cited above are generally recognized although not completely quantified. Chlorinated solvents currently are under intensive study.

6. Some VOC are of such low photochemical reactivity that they persist in the atmosphere for several years, eventually migrating to the stratosphere where they are suspected of reacting and destroying ozone. Since stratospheric ozone is the principal absorber of ultraviolet (UV) light, the depletion could lead to an increase in UV penetration with a resultant worldwide increase in skin cancer. The only in-depth analysis of this potential problem has focused on the chlorofluoromethanes (CFM), Freon 11 and Freon 12, because of their known stability and widespread use in aerosol containers. A report of the National Academy of Sciences concerning environmental effects of CFM's concluded that:

... selective regulation of CFM uses and releases is almost certain to be necessary at some time and to some extent of completeness.

In response to the report of the National Academy of Sciences and other studies, EPA on May 13, 1977 (42 FR 24542), proposed rules to prohibit nonessential usage of fully halogenated chlorofluoromethanes as aerosol propellants. The restrictions were applied to all members of this class including Freon 113 since they are potential substitutes for Freon 11, Freon 12, Freon 114, and Freon 115 which are currently used as aerosol propellants.

Other stable halogenated solvents which are released in volumes comparable to the chlorofluoromethanes also are suspected of depleting the earth's UV shield. Of major concern is the wide-

spread substitution of methyl chloroform (1,1,1 trichloroethane) for the photochemically reactive degreasing solvent trichloroethylene. Such substitution under Rule 66 generation regulations has already influenced industrial degreasing operations to the extent that methyl chloroform production has surpassed that of trichloroethylene in the United States. Any regulation in the area will have a marked effect on the production and atmospheric emissions of both solvents. Endorsing methyl chloroform substitution would increase emissions, particularly in industrial States that have not, heretofore, implemented Rule 66. On the other hand, disallowing methyl chloroform as a substitute or banning it altogether would significantly increase emissions of trichloroethylene even if degreasers were controlled to the limits of available technology. Presently, technology is only able to reduce emissions by approximately 50 percent. In metropolitan areas which have already implemented Rule 66, a return to trichloroethylene would have an adverse effect on ambient oxidant levels. In addition to being highly reactive, trichloroethylene has been implicated as a carcinogen.

Alternatives to the above-cited choices would be (1) development and application of highly efficient degreaser control systems and (2) replacement with an

intermediate solvent which is neither reactive nor detrimental to the upper atmosphere. Major revisions would be needed to degreaser designs to improve vapor capture above the current best level. Anticipated design changes could add materially to degreaser costs. No alternative solvent is clearly acceptable from the standpoints of photochemical oxidant and stratospheric ozone depletion. Neither methylene chloride nor trichlorotrifluoroethane are reactive, but, like methyl chloroform, are suspected of causing damage to the stratospheric ozone layer. In addition, methylene chloride is a suspect mutagen. Perchloroethylene, the principal dry cleaning solvent, does not present a hazard to the stratosphere but has been implicated as being a carcinogen and also reacts slowly in the atmosphere to form oxidant.

7. Organic solvents of low or negligible photochemical reactivity have only limited use in many industries. Most are chlorinated organics that find principal applications as cleaners for metals and fabrics. A few nonhalogenated VOC such as acetone, methyl ethyl ketone, and isopropanol are of low reactivity but these can't possibly satisfy all the myriad needs of the paint, plastics, pharmaceutical, or many other industries. While users of reactive VOC usually can employ effective control equipment to recover or

destroy VOC emissions, they seldom have the option of applying reactivity considerations in choosing solvents. Applying reactivity restrictions to the surface coating industry would be especially disadvantageous since it would greatly inhibit the development of low-solvent coatings; essentially all of the organic solvents used to constitute high-solids coatings and water-borne coatings are, in fact, highly reactive.

8. It is recognized that smog chamber studies conducted to date are incomplete because many organic compounds have not been examined and it has been impossible to duplicate all atmospheric situations. For example, there has been only limited examination of oxidant formation under relatively high ratios of VOC to NO_x (30:1 and greater), comparable to rural conditions. Any policy on photochemical reactivity necessarily has to be open to revision as new information is developed which may show specific organic compounds to be more or less photochemically reactive than indicated by current data.

Dated: June 23, 1977.

EDWARD F. TURNER,
Acting Assistant Administrator
for Air and Waste Management.
[EPA Doc. 77-15005 Filed 7-7-77; 9:45 am]

Review under 42 U.S.C. § 719(b) (1977 Supp.) from an order of the Secretary of Energy.

Copies of the petition for review have been served on the Secretary, Department of Energy, and all participants in prior proceedings before the Secretary.

Any person desiring to be heard with reference to such filing should on or before June 12, 1979, file a petition to intervene with the Federal Energy Regulatory Commission, 625 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with the Commission's rules of practice and procedure (18 CFR 1.8). Any person wishing to become a party or to participate as a party must file a petition to intervene. Such petition must also be served on the parties of record in this proceeding and the Secretary of Energy through Gaynell C. Methvin, Deputy General Counsel for Enforcement and Litigation, Department of Energy, 12th and Pennsylvania Ave., N.W., Washington, D.C. 20461. Copies of the petition for review are on file with the Commission and are available for public inspection at Room 1000, 625 North Capitol St., N.E., Washington, D.C. 20426.

Kenneth F. Plumb,
Secretary.

(FR Doc. 79-0720 Filed 5-3-79 9:45 am)
BILLING CODE 6450-01-0

[Docket No. R79-36]

Triton Oil & Gas Corp.; Petition for Declaratory Order

May 21, 1979.

Take notice that on April 5, 1979, Triton Oil and Gas Corporation (Triton), One Energy Square, 4625 Greenville Avenue, Dallas, Texas 75206 filed in Docket No. R79-36 a petition for declaratory order pursuant to Section 1.7 of the Commission's Rules of Practice and Procedure. Triton requests a determination that it has no refund obligation under Southern Louisiana Area Rate Opinion No. 398 for rates it collected for certain sales of gas. The gas is produced from four fields in the Southern Louisiana Area and sold to Tennessee Gas Pipeline Company, Texas Gas Transmission Company and Southern Natural Gas Company under Triton's Rate Schedules 1 and 8, A, and 7 respectively.

On June 6, 1979, the Commission directed Triton, among other producers, to disburse refunds for the period from October 1966 to January 1971 pursuant to the Commission's Opinion No. 398

and 398-A or show cause why such refunds were not due. Triton's position is that because sales under these rate schedules were authorized by permanent certificates of public convenience and necessity which contained no refund conditions, there is no refund obligation. Triton acknowledges that the Commission may order refunds and reductions in rates after August 1, 1971—the effective date of Opinion No. 398. However, it asserts that the Commission is without authority to order such adjustments prior to the effective date where rates were not collected subject to a suspension order or under a temporary certificate.

Any person desiring to be heard or to make any protest with reference to said petition should file a petition to intervene or a protest with the Federal Energy Regulatory Commission, 625 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with requirements of the Commission's rules of practice and procedure (18 C.F.R. 1.8 or 1.10). All such petitions or protests should be filed on or before June 20, 1979. All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding, or to participate as a party in any hearing therein, must file a petition to intervene in accordance with the Commission's rules.

Kenneth F. Plumb,
Secretary.

(FR Doc. 79-0720 Filed 5-3-79 9:45 am)
BILLING CODE 6450-01-0

[Docket No. R79-46]

United Gas Pipe Line Co.; Informal Settlement Conference

May 21, 1979.

Take notice that on June 7, 1979, at 1:30 p.m. an informal conference of all interested persons will be convened for the purpose of continued settlement discussions in this proceeding. The conference will be held in Room 3200 of the Federal Energy Regulatory Commission at 943 North Capitol Street, N.E., Washington, D.C. 20426.

Customers and other interested persons will be permitted to attend, but if such persons have not previously been permitted to intervene by order of the Commission, attendance will not be deemed to authorize intervention as a party in this proceeding.

All parties will be expected to come fully prepared to discuss the merits of the issues arising in this proceeding and to make commitments with respect to such issues and any offers of settlement or stipulation discussed at the conference.

Lois D. Cashell,

Acting Secretary.

(FR Doc. 79-0721 Filed 5-3-79 9:45 am)
BILLING CODE 6450-01-0

Office of Energy Conservation and Solar Applications

Meeting Regarding Emergency Building Temperature Restrictions Program

Notice is hereby given that the Department of Energy (DOE) will hold a meeting with the National Governors' Association on Friday, June 8, 1979, at 11 a.m. in Room 2B5, 444 North Capitol Street, Washington, D.C.

The purpose of the meeting will be to discuss the role of the States in implementing the Emergency Building Temperature Restrictions Program. This program is authorized by the President's "Standby Conservation Plan No. 2: Emergency Building Temperature Restrictions," which recently was approved by the Congress.

Issued in Washington, D.C. on May 31, 1979.

Mauden Savits,
Deputy Assistant Secretary, Conservation and Solar Applications.

(FR Doc. 79-0720 Filed 5-3-79 12:00 pm)
BILLING CODE 6450-01-0

ENVIRONMENTAL PROTECTION AGENCY

(FRL 1239-61)

Air Quality; Clarification of Agency Policy Concerning Ozone SIP Revisions and Solvent Reactivities

ACTION: This notice is published under the authority of section 101(b) and section 108 of the Clean Air Act. The notice clarifies EPA's "Recommended Policy on Control of Volatile Organic Compounds," 42 FR 35314 (July 6, 1977).

STATEMENT: The July 1977 Policy Statement noted that only reactive volatile organic compounds participate in the chemical reactions that form photochemical oxidants. Currently available information suggests that negligibly photochemically reactive volatile organic compounds as defined in that Statement, including methyl

chloroform and methylene chloride, do not appreciably affect ambient ozone levels. Hence, EPA will not disapprove any state implementation plan or plan revision for its failure to contain regulations restricting emissions of these compounds.

Although these substances need not be controlled under state implementation plans for the purpose of achieving ambient ozone standards, nothing in this memorandum is intended to modify past EPA expressions of concern about the uncontrolled use of methyl chloroform and methylene chloride. As noted in the above referenced policy and the clarification presented in memoranda of August 24, 1978 and March 6, 1979, there is suggestive evidence that both compounds are potentially carcinogenic and methyl chloroform is suspected of contributing to depletion of stratospheric ozone. See, for example, the following studies:

Simmons, V. F., Kauhanen, K. and Tardiff, R. G., "Mutagenic Activity of Chemicals Identified in Drinking Water in Progress in Genetic Toxicology, ed. I. D. Scott, B. A. Bridges, and F. H. Sobels, at 249-258 (Elsevier, 1977);

Price, P. G., Hassett, C. M. and Maasfield, O. L., "Transforming Activities of Trichloroethylene and Proposed Industrial Alternatives" *In Vitro* 14:3, at 280-283 (1978);

Thelma, J. C., Stoner, G. D., Shimkin, M. B., et al., "Test for Carcinogenicity of Organic Contaminants of United States Drinking Waters by Pulmonary Tumor Response in Strain A Mice," *Cancer Research*, 37(8 Pt. 1): 2717-20, (August 1977);

The EPA Carcinogen Assessment Group's Preliminary Risk Assessment on Methyl Chloroform, Type I—Air Program, (January 17, 1979);

The EPA Carcinogen Assessment Group's Preliminary Risk Assessment on Methylene Chloride, Type I—Air Program, (January 17, 1979);

Conference on Methyl Chloroform and other Halocarbon Pollutants, sponsored by Environmental Sciences Research Laboratory, U.S. EPA, February 27-28, 1979, Washington, D.C. (proceedings in press).

Because both methyl chloroform and methylene chloride are potentially harmful, EPA recommends that these chemicals not be substituted for other solvents in efforts to reduce ozone concentrations. EPA further recommends that the states control these compounds under the authority reserved to them in section 118 of the Clean Air Act. Moreover, there is a strong possibility for future regulation of

these compounds under the Clean Air Act.

FOR FURTHER INFORMATION CONTACT: Joseph Padgett, Director, Strategies and Air Standards Division, Office of Air Quality Planning and Standards, MD-12 Research Triangle Park, North Carolina 27711 (919) 541-6204.

Dated: May 23, 1979.
David G. Hawkins,
Assistant Administrator for Air, Noise and Radiation.

(FR Doc. 79-17280 Filed 5-1-79 9:45 am)
BILLING CODE 6050-01-0

(FRL 1239-3)

Region II; Groundwater System of the New Jersey Coastal Plains Aquifer

On March 21, 1979, a notice was published stating that a petition has been submitted by the Environmental Defense Fund, Inc. and the Sierra Club-New Jersey Chapter, pursuant to Section 1424(s) of the Safe Drinking Water Act, Pub. L. 95-523, requesting the Administrator of the Environmental Protection Agency to make a determination that the aquifer underlying the Counties of Monmouth, Burlington, Ocean, Camden, Gloucester, Atlantic, Salem, Cumberland and Cape May and portions of Mercer and Middlesex Counties, New Jersey is the sole or principal drinking water source for the coastal plain area which, if contaminated, would create a significant hazard to public health.

The notice indicated that comments, data and references in response to the petition should be submitted by May 21, 1979. Due to the complexity of issues which surround the designation of the Coastal Plain Area as a sole source aquifer, EPA was requested to extend the comment period. In order to permit sufficient time for all interested individuals to provide their input, EPA will extend the comment period on this petition request from May 21, 1979 to August 20, 1979. Comments, data and references in response to the Coastal Plain Petition should be submitted in writing to Eckardt C. Beck, Regional Administrator, Region II, Environmental Protection Agency, 28 Federal Plaza, Room 1008, New York, N.Y. 10007. Attention: Coastal Plain Aquifer. Information concerning the Coastal Plain Aquifer System will be available for inspection at the above address.

Dated: May 21, 1979.

Eckardt C. Beck,
Regional Administrator.
(FR Doc. 79-17280 Filed 5-1-79 9:45 am)
BILLING CODE 6050-01-0

(FRL 1239-3 OPP-00098)

State-FIFRA Issues Research and Evaluation Group (SFIREG); Working Committee on Enforcement; Open Meeting

AGENCY: Environmental Protection Agency (EPA), Office of Pesticide Programs.

ACTION: Notice of Open Meeting.

SUMMARY: There will be a two-day meeting of the Working Committee on Enforcement of the State-FIFRA Issues Research and Evaluation Group (SFIREG) on Tuesday and Wednesday, June 5-6, 1979, beginning at 8:30 a.m. each day, and concluding by 12 noon on June 6th. The meeting will be held at the Atlanta Town House, 100 Tenth Street, N.W., Atlanta, Georgia. Telephone: 404/522-6900, and will be open to the public.

FOR FURTHER INFORMATION CONTACT: Mr. William Buffaloe, North Carolina Department of Agriculture, Raleigh, North Carolina. Telephone: 919/733-3888; or Mr. Anthony Dellavocchia, Pesticide and Toxic Substances Enforcement Division, EPA, 401 M Street, S.W., Washington, D.C., telephone: 202/735-0814.

SUPPLEMENTARY INFORMATION: This is the second meeting of the Working Committee on Enforcement. The meeting will be concerned with the following topics:

1. Plan for future recall and suspension orders;
2. Clarification of undefined terms in Section 26 and 27 of FIFRA;
3. Status of State primacy use enforcement action;
4. Use of recommendations of agricultural extension publications by pesticide sales representatives;
5. Discussion of definition of "non crop land";
6. FIFRA Section 7—producers of active ingredients; and
7. Other enforcement matters which may arise.

Dated: May 23, 1979.
Edwin L. Johnson,
Deputy Assistant Administrator for Pesticide Programs.
(FR Doc. 79-17280 Filed 5-1-79 9:45 am)
BILLING CODE 6050-01-0

Included within the definition of non-target sites are areas of permanent human habitation including permanent residences, schools, churches, and areas in which substantial commercial activities are conducted (e.g., shopping centers), domestic enterprises, and publicly-maintained roads. In addition, aquatic habitats such as critical fisheries, municipal water supply intakes and other waters (which include rivers, streams, ponds, lakes, and ephemeral streams and ponds with flowing or standing water visible from an aircraft flying at an altitude of 1,000 feet above the terrain at the time of treatment), are included within the definition of a sensitive area. The release of any pesticide spray is not permitted over a sensitive area or in the surrounding buffer zone. Buffer zones are defined as areas intended to receive only spray drift fallout from the application sites.

The Agency recognizes that some seasonal dwellings, such as hunting and fishing camps, may be located in or adjacent to the treatment area. These dwellings are not considered to be permanent residences and thus will not be buffered against direct application. However, many of these dwellings are near aquatic sites listed in Table II which will be buffered.

To minimize operational errors, overflights of the treatment area prior to the actual spray operation are encouraged. The purpose of these overflights is to locate visually all sensitive areas and buffer zones designated on the spray block maps. Particular attention should be given to identifying ephemeral streams and ponds visible from an aircraft flying at an altitude of 1,000 feet or less above the terrain at the time of treatment, which may not be designated on the spray block map due to their seasonality.

Authority

This Advisory Opinion governing the use of certain insecticides for the suppression of the spruce budworm in Maine through July, 1980, is issued pursuant to the authority granted to the Administrator by Section 2(ee) of FIFRA, 7 U.S.C. 136(ee) (Supp. 1979). Section 12(a)(2)(G) of FIFRA makes it unlawful for any person "to use any registered pesticide in a manner inconsistent with its labeling." Section 2(ee) defines this terminology as prohibiting the use of registered pesticide "in a manner not permitted by the labeling." However, section 2(ee) also provides that this prohibition does not apply with respect to "any use of a pesticide in a manner that the Administrator determines to be

consistent with the purposes of this Act."

Effective Date: This Notice is effective through July 31, 1980.

Dated: May 8, 1980.

Steven E. Jullinek,
Assistant Administrator for Pesticides and
Toxic Substances.

EPR Doc. 80-0157 Filed 5-15-80 9:45 am
CALLING CODE 0000-01-01

[FRL 1483-7]

Air Quality: Clarification of Agency Policy Concerning Ozone SIP Revisions and Solvent Reactivities

SUMMARY: This notice is published under the authority of § 101(b) and § 103 of the Clean Air Act. The notice provides further clarification of a policy announced in EPA's "Recommended Policy on the Control of Volatile Organic Compounds," 42 FR 35314 (July 8, 1977) and "Clarification of Agency Policy Concerning Ozone SIP Revisions and Solvent Reactivities," 44 FR 32043 (June 4, 1979).

DISCUSSION: The previous policy statements on the control of volatile organic compounds (VOC's) noted that methyl chloroform and methylene chloride are negligibly photochemically reactive and do not appreciably contribute to the formation of ozone. Consequently, controls on emissions of these two compound would not contribute to the attainment and maintenance of the national ambient air quality standards for ozone. In the June 1979 policy statement EPA explained that it would not disapprove any state implementation plan (SIP) or plan revision for its failure to contain regulations restricting emissions of methyl chloroform and/or methylene chloride.

Today's statement clarifies EPA policy regarding state implementation plan submittals which do contain regulations restricting emissions of the two compounds. Section 110(a)(1) of the Clean Air Act limits state implementation plans to measures designed to achieve and maintain the national ambient air quality standards (NAAQS). Because current information indicates that emissions of methyl chloroform and methylene chloride do not appreciably affect ambient ozone levels, EPA cannot approve measures specifically controlling emissions of either or both compounds as part of a federally enforceable ozone SIP. EPA will take no action on any measures specifically controlling emissions of the two compounds which are submitted by the states as ozone SIP measures for

EPA approval. If a state chooses to control emissions of these compounds, such measures will be considered as state regulations only and not as part of an ozone SIP. EPA will not enforce controls on emissions of either methyl chloroform or methylene chloride adopted by the state as part of an implementation plan for ozone.

States retain authority to control emissions of these compounds under the authority reserved to them under Section 116 of the Clean Air Act. For further information relevant to the exercise of this authority see the July 8, 1977 and June 4, 1979 policy statements. This policy notice should not be read as a statement of EPA's views on the desirability of controls on these substances.

Finally, EPA wishes to point out that this policy notice addresses only the Agency's lack of authority to include in federally approved SIPs controls on substances whose emissions do not contribute, either directly or indirectly, to concentrations of pollutants for which NAAQS have been established under section 108 of the Act. This policy notice does not address the question of SIP measures which control substances contributing to concentrations of pollutants for which NAAQS have been established, but which are contended to be more strict than absolutely necessary to attain and maintain the NAAQS. EPA has no authority to exclude such measures from SIPs.

FOR FURTHER INFORMATION CONTACT:
G. T. Helms, Chief, Control Programs
Operations Branch (MD-15), Research
Triangle Park, North Carolina 27711.
(919) 541-3226, FTS 629-3226.

Dated: May 8, 1980.

David G. Hewkins,
Assistant Administrator for Air, Noise and
Radiation.

EPR Doc. 80-15130 Filed 5-15-80 9:45 am
CALLING CODE 0000-01-01

[FRL 1481-7; PP 601607/T239]

Extension of a Temporary Tolerance

AGENCY: Environmental Protection
Agency (EPA).

ACTION: Notice.

SUMMARY: EPA has extended the temporary tolerance for residues of the herbicide thidiazuron (N-phenyl-N'-1,2,3-thiadiazol-5-ylurea) and its aniline-containing metabolites in or on the raw agricultural commodities cottonseed at 0.2 part per million (ppm), milk 0.05 ppm, eggs 0.1 ppm, meat fat and meat byproducts of cattle, goats, hogs, horses, poultry, and sheep at 0.2 ppm.

Dempanco Service Sta. U.S. 1 and Hwy A1A,
June Beach, FL 32408—5-14-80
Per Mobil, 324 Par Avenue, Orlando, FL
32804—3-18-80
John Gibben, I-85 and KY 80, Cave City, KY
42127—3-18-80
Belmeade Shell, 5315 S. Harding, Nashville,
TN 37205—3-19-80
Corner Store, 1401 No. Main Street,
Kissimmee, FL 32744—3-19-80
Kopper Kettle, Highway 100 & I-45, Franklin,
KY 42134—4-7-80
Buechel Terrace Chevron, 4218 Bardstown
Rd., Louisville, KY 40218—4-10-80
LaPorte Exxon, 1823 S. Federal Hwy.,
Hollywood, FL 33030—4-21-80
Riser's Chevron, 3430 Lebanon Road,
Hermitage, TN 37075—4-13-80
Douglas Amoco Service, 583 Donaldson Pike,
Nashville, TN 37214—4-14-80
Town & River Texaco, 1034 Cypress Lake
Rd., Ft. Meyers, FL 33907—4-14-80
Trail Sunoco, 8158 So. Tamiami Trail, Ft. Meyers,
FL 33907—4-14-80
Viles Chevron, 8180 So. Tamiami Trail, Ft.
Meyers, FL 33907—4-14-80
Port Comfort, Box 105, Rt. 34, Ft. Meyers, FL
33908—4-15-80
Castro's Exxon, 1910 Dickerson Rd.,
Nashville, TN 37207—4-15-80
Barker Westgate Standard, 2510 Pio Nono
Ave., Macon, GA 31206—4-15-80
Seminole Exxon, 1948 W. Tenn. Tallahassee,
FL 32304—4-15-80
Fred Halsey's Chevron, 3012 Remoiner Road,
Macon, GA 31204—4-25-80
Winston Chevron, 625 Madison Street,
Huntsville, AL 35801—4-25-80
H & A Fuel Service, P.O. Box 468, Hardsville,
SC 29823—4-25-80
Chancy's Standard, P.O. Box 1708, St. Simons
Island, GA 31523—4-25-80
Norman's Standard, 3304 Glynn Avenue,
Brunswick, GA 31520—4-25-80
Plaza Standard, 1966 Glynn Avenue,
Brunswick, GA 31520—4-25-80
Coley's Exxon, Rt. 1 I-95 and SC 290, Duncan,
SC 29334—4-25-80
Bingham's Texaco, Rt. 1 I-95 and SC 290,
Duncan, SC 29334—4-25-80
White's Exxon, Hwy I-95 and SC-8,
Spartanburg, SC 29303—4-25-80
Mauldin Chevron, 804 N. Main, Mauldin, SC
29662—4-25-80
Wade Hampton Mall Exxon, 1035 Wade
Hampton Blvd., Greenville, SC 29609—4-
25-80
Harris Standard, P.O. Box 408, Nahant, GA
31533—4-25-80
Pittman's Standard, I-75 and Jullens Rd.,
Forsyth, GA 31029—4-30-80
Trout's Texaco, 108 N A 1 A Hwy, Satellite
Beach, FL 32837—4-30-80
Magnolia Plantation, P.O. Drawer, Tifton, GA
31794—4-30-80
M & M 78, 1100 SR 524 Rt. 1, Cocoa, FL
32922—4-30-80

Issued in Atlanta, Georgia on the 11th day
of July 1980.

James C. Easterday,

District Manager.

Concurrence:

Leonard F. Bitman,

Chief Enforcement Counsel.

(FR Doc. 80-21264 Filed 7-21-80; 9:45 am)

BILLING CODE 6450-01-02

ENVIRONMENTAL PROTECTION AGENCY

[FRL 1545-7]

**Air Quality; Clarification of Agency
Policy Concerning Ozone SIP
Revisions and Solvent Reactivities**

AGENCY: Environmental Protection
Agency (EPA).

ACTION: Notice.

BACKGROUND: This notice is published
under the authority of section 101(b) and
section 103 of the Clean Air Act. The
notice provides further clarification of a
policy announced in EPA's
"Recommended Policy on the Control of
Volatile Organic Compounds," 42 FR
35314 (July 6, 1977) and "Clarification of
Agency Policy Concerning Ozone SIP
Revisions and Solvent Reactivities," 44
FR 32042 (June 4, 1979) and 45 FR 32424
(May 18, 1980).

DISCUSSION: The previous policy
statements on the control of volatile
organic compounds (VOCs) noted that
despite concerns about their potential
toxicity 1,1,1-trichloroethane (methyl
chloroform) and methylene chloride are
negligibly photochemically reactive and
do not appreciably contribute to the
formation of ozone. Today's statement
expands the list (45 FR 32424) of organic
compounds (VOCs) of negligible
photochemical reactivity to include the
following chlorofluorocarbons (CFC) or
fluorocarbons (FC):
trichlorofluoromethane (CFC-11);
dichlorodifluoromethane (CFC-12);
chlorodifluoromethane (CFC-22);
trifluoromethane (FC-23);
trichlorotrifluoroethane (CFC-113);
dichlorotetrafluoroethane (CFC-114);
and chloropentafluoroethane (CFC-115).

EPA has determined that these
halogenated compounds are no more
photochemically reactive than methyl
chloroform and methylene chloride and
do not appreciably contribute to the
formation of ambient ozone.
Consequently, controls on emissions of
these compounds would not contribute
to the attainment and maintenance of
the national ambient air quality
standards for ozone. EPA cannot
approve or enforce controls on these

compounds as part of a Federally
enforceable ozone State Implementation
Plan (SIP). EPA will take no action on
any measures specifically controlling
emissions of these compounds which
are submitted by the States as ozone SIP
measures for EPA approval. (See 45 FR
32424.)

However, EPA would like to reiterate
its continuing concern over the possible
environmental effects from emissions of
these compounds. As such, EPA is not
precluding the possible future regulation
of these compounds.

It should be recognized that the two
halogenated compounds, methyl
chloroform and CFC-113, stated to be of
negligible photochemical reactivity in
the July 6, 1977 Federal Register, have
been implicated in the depletion of the
stratospheric ozone layer. This layer is a
region of the upper atmosphere which
shields the earth from harmful
wavelengths of ultraviolet radiation that
increase the risk of skin cancer in
humans.

In response to this concern, the
Agency promulgated on March 17, 1978
(43 FR 11318), rules under the Toxic
Substances Control Act (TSCA) to
prohibit the nonessential use of fully
halogenated chlorofluoroalkanes as
aerosol propellants. Restrictions were
applied to all members of this class,
including CFC-113, since they are
potential substitutes for CFC-11, CFC-
12, CFC-114, and CFC-115, which are
currently used as aerosol propellants.
The Agency is investigating control
options and substitutes for
nonpropellants.

EPA has proposed new source
performance standards under Section
111 for organic solvent cleaners (45 FR
39786, June 11, 1980). These proposed
standards would limit emissions of the
reactive volatile organic compounds
trichloroethylene and perchloroethylene
as well as methyl chloroform, methylene
chloride, and trichlorotrifluoroethane
(CFC-113) from new, modified, or
reconstructed organic solvent
degreasers. If these standards are
promulgated, EPA will develop a
guideline document for States to use in
developing regulations required under
Section 111(d) for existing organic
solvent cleaners that use any of the
designated compounds.

Whether, and to what extent, methyl
chloroform and methylene chloride are
human carcinogens or have other toxic
effects, and to what extent methyl
chloroform, CFC-113, and other CFCs
deplete the ozone layer, are issues of
considerable debate. Detailed health
assessments of methyl chloroform,
methylene chloride, and CFC-113 are
being prepared by EPA's Office of

Research and Development. These assessments will be submitted for external review, including a review by the Science Advisory Board, prior to promulgation of the regulations and the proposal of EPA guidance to States for developing existing source control measures. The extent to which the preliminary findings are affirmed by the review process may affect the final rulemaking for new as well as existing sources.

Until these issues of environmental impact are fully resolved, EPA remains concerned that if these chemicals are exempted from regulation, the substitution of exempt for nonexempt solvents could result in large increases of emissions of pollutants that may have adverse health impacts.

The emissions of CFC-22 and FC-23, also of relatively low photochemical reactivity, are of continuing concern with regard to possible environmental effects. Consequently, EPA is not precluding the possible future regulation of these compounds as well.

Finally, EPA wishes to point out that this notice addresses only the Agency's lack of authority to include in Federally approved SIPs controls on substances whose emissions do not contribute, either directly or indirectly, to concentrations of pollutants for which NAAQS have been established under Section 109 of the Act. This policy notice does not address the question of SIP measures which control substances contributing to concentrations of pollutants for which NAAQS have been established, but which are contended to be more strict than absolutely necessary to attain and maintain the NAAQS. EPA has no authority to exclude such measures from SIPs.

FOR FURTHER INFORMATION CONTACT: G. T. Helms, Chief, Control Programs Operations Branch (MD-15), Research Triangle Park, North Carolina 27711. (919) 541-8228, FTS 829-8228.

Dated: July 18, 1980.

David G. Howkins,
Assistant Administrator for Air, Noise, and Radiation.

(FR Doc. 80-1788 Filed 7-21-80; 8:45 am)
DOLLAR CODE 0000-01-01

[FRL 1548-6]

California State Motor Vehicle
Pollution Control Standards; Public
Hearing

AGENCY: Environmental Protection
Agency (EPA).

ACTION: Notice of public hearing on

requests for waivers of Federal
preemption.

SUMMARY: The California Air Resources Board (CARB) notified EPA of two recent amendments to California's emission standards and test procedures for motor vehicles produced by certain small-volume manufacturers, and requested a waiver of Federal preemption for each amendment. EPA will consider these waiver requests, among other issues, at a public hearing already scheduled for July 24, 1980 at EPA's San Francisco office, as announced in a Federal Register notice of July 3, 1980.

DATES: Hearing July 24, and if necessary July 25, 1980.

ADDRESSES: EPA will consider the waiver requests at a public hearing held at: U.S. Environmental Protection Agency Regional Office (Region IX), Nevada Room, Sixth Floor, 215 Fremont Street, San Francisco, California. Copies of all materials relevant to the hearing are available for public inspection during normal working hours (8:00 a.m. to 4:30 p.m.) at: U.S. Environmental Protection Agency, Public Information Reference Unit, Room 2922 (EPA Library), 401 M Street, SW., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Glenn Unterberger, Chief, Waivers Section, Manufacturers Operations Division (EN-340), U.S. Environmental Protection Agency, Washington, D.C. 20460. (202) 472-0421.

SUPPLEMENTARY INFORMATION:

I. Background and Discussion

Section 208(a) of the Clean Air Act, as amended, 42 U.S.C. 7543(a) ("Act"), provides in part: "No state or any political subdivision thereof shall adopt or attempt to enforce any standard relating to control of emissions from new motor vehicles or new motor vehicle engines subject to this part . . . (or) require certification, inspection, or any other approval relating to the control of emissions . . . as condition precedent to the initial retail sale, titling (if any), or registration of such motor vehicle, motor vehicle engine, or equipment."

Section 208(b)(1) of the Act requires the Administrator, after notice and opportunity for public hearing, to waive application of the prohibitions of section 208 to any State which had adopted standards (other than crankcase emission standards) for the control of emissions from new motor vehicles or new motor vehicle engines prior to March 30, 1966, if the State determines

that the State standards will be, in the aggregate, at least as protective of public health and welfare as applicable Federal standards. The Administrator must grant a waiver unless he finds that: (1) The determination of the State is arbitrary and capricious, (2) the State does not need the State standards to meet compelling and extraordinary conditions, or (3) the State standards and accompanying enforcement procedures are inconsistent with section 202(a) of the Act.

Pursuant to these provisions, the Administrator of EPA granted California waivers of Federal preemption allowing the State to enforce its exhaust emission standards for 1979 and subsequent model year passenger cars¹ and for 1979 and subsequent model year light-duty trucks (LDTs) and medium-duty vehicles (MDVs).² In *American Motors Corp. v. Blum*³, the D.C. Circuit held that section 202(b)(1)(B) of the Act entitled American Motors Corporation (AMC) to two additional years of lead time to meet certain California oxide of nitrogen (NO_x) emission standards for passenger cars.

As a result, in a Federal Register notice issued July 3, 1980, the Administrator modified his passenger car waiver decision with respect to 1980 and 1981 model year AMC passenger cars, and announced a public hearing to reconsider the earlier LDT/MDV waiver decisions in light of *AMC v. Blum*.⁴ The notice further provided that EPA would consider at the public hearing any waiver requests filed by California, or before July 7, 1980 to cover amended NO_x standards and enforcement procedures for 1980 and later model year passenger cars and 1981 and later year passenger cars and 1981 and later year model year LDTs and MDVs manufactured by AMC.

In a June 13, 1980 letter to the Administrator, CARB notified EPA that it had taken several actions to revise California's new motor vehicles emissions control program in response to *AMC v. Blum*. CARB requested a waiver of Federal preemption for the following items:

(i) Amendments to exhaust emission standards and test procedures for 1980 and later model year passenger cars, light-duty trucks and medium-duty

¹ 43 FR 25729 (June 14, 1978).

² 43 FR 1829 (January 12, 1978) (for California's 1979-1982 model year LDTs and MDVs); 43 FR 13488 (April 13, 1978) (for California's 1980 and later model year LDTs and MDVs).

³ 608 F. 2d 979 (D.C. Cir. 1979).

APPENDIX H
CHEMICAL SCREENING ANALYSIS DATA

APPENDIX H

CHEMICAL SCREENING ANALYSIS DATA

This appendix provides a detailed presentation and description of the data and programs used to derive the results discussed in Section 9.2. The appendix includes in Section H.1 a description and a list of the affected chemicals used in the screening analysis. Section H.2 describes all input data used in the analysis including relevant assumptions made. Section H.3 is a brief explanation of the logic of the screening analysis program accompanied by a printout of the program itself. The results of the screening analysis are described and listed in Section H.4. A separate discussion follows in Section H.5 of the program and inputs used to determine the quantity and distributional impacts, along with the results. Finally, Section H.6 details the production process routes that are used for each chemical in the roll-through price increase calculation.

This appendix is intended to be a point of reference for questions arising from the price impacts analysis of Section 9.2. A brief discussion of the logic of the computer program and the specific data used are provided here. Although some discussion of the approach and of the basis for assumptions made in the screening analysis is presented, Section 9.2 should be read for a more in-depth discussion.

H.1 CHEMICALS AFFECTED

Table H-1 provides an alphabetical and numerical list of 240 chemicals which is used to define the members of the SOCFI industry. Included in this list are the 173 chemicals defined as the large-volume chemicals produced by reactor processes in Section 9.1.2, and 16 chemicals that are process route inputs to these 173 but are not produced themselves by reactor processes. An additional 51 chemicals are included in Table H-1 but are not specifically used in production by reactor processes. The chemicals are arranged alphabetically by chemical name and numerically by number in the data sets. Also included is each chemical's common name, if different from its chemical name. Several characteristics of this list warrant special notice.

First, the chemicals are numbered 1 to 257, but 17 of the numbers have no chemical assigned to them and do not appear in Table H-1 or in the screening analysis data sets. These 17 numbers are, 59, 100, 218, 219, 229, 231, 233, 241, 242, 243, 244, 245, 246, 247, 253, 255, 256. Second, there are 51 other numbers that do not appear in the screening analysis data sets, and they represent the 51 chemicals in Table H-1

TABLE H-1. LIST OF CHEMICALS BY CHEMICAL NUMBER

Chemical number	Chemical name	Common name
1	Acetaldehyde	--
2	Acetic acid	--
3	Acetic acid, anhydride	(1) Acetic anhydride (2) Acetic oxide
4	Acetic acid, butyl ester	n-Butyl acetate
5	Acetic acid, ethenyl ester	Vinyl acetate
6	Acetic acid, ethyl ester	Ethyl acetate
7	Acetic acid, magnesium salt ^a	Magnesium acetate
8	Alcohols, C-11 or lower, mixtures	--
9	Alcohols, C-12 or higher, mixtures	--
10	2-Aminoethanol	Ethanolamine
11	Benzenamine	(1) Aniline (2) Phenylamine
12	Benzene	Benzol
13	1,3-Benzenedicarboxylic acid ^a	Isophthalic acid
14	1,4-Benzenedicarboxylic acid	Terephthalic acid
15	1,2-Benzenedicarboxylic acid, bis (2-ethylhexyl) ester	(1) Bis (2-ethylhexyl) phthalate (2) Dioctyl phthalate (3) Di (2-ethylhexyl) phthalate
16	1,2-Benzenedicarboxylic acid, butyl, phenylmethyl ester	Butylbenzyl phthalate
17	1,2-Benzenedicarboxylic acid, di-n-heptyl-n-nonyl undecyl ester ^b	Di-n-heptyl-n-nonyl undecyl phthalate
18	1,2-Benzenedicarboxylic acid, diisodecyl ester	Diisodecyl phthalate

(See footnotes at end of table).

(continued)

TABLE H-1 (continued)

Chemical number	Chemical name	Common name
19	1,2-Benzenedicarboxylic acid, diisononyl ester ^a	Diisononyl phthalate
20	1,4-Benzenedicarboxylic acid dimethyl ester	(1) Terephthalic acid, dimethyl ester (2) Dimethylterephthalate (3) DMT
21	Benzenesulfonic acid	--
22	Benzenesulfonic acid, mono-C ₁₀₋₁₆ alkyl derivatives, sodium salts	--
23	Benzoic acid, technical ^a	--
24	1,1'-Biphenyl ^a	Diphenyl
25	2,2-Bis(hydroxymethyl)-1,3-propanediol	Pentaerythritol
26	1,3-Butadiene	(1) Bivinyll (2) Divinyll
27	Butadiene and butene fractions	
28	Butanal	Butyraldehyde
29	Butane	n-Butane
30	Butanes, mixed	--
31	1,2-(and 1,3-) Butanediol ^a	Butylene glycol
32	1,4-Butanediol	--
33	Butanoic acid, anhydride	Butyric anhydride
34	1-Butanol	n-Butyl alcohol
35	2-Butanol	sec-Butyl alcohol
36	2-Butanone	Methyl ethyl ketone
37	1-Butene	a-Butylene

(See footnotes at end of table)

(continued)

TABLE H-1 (continued)

Chemical number	Chemical name	Common name
38	2-Butene	(1) β -Butylene (2) pseudo-Butylene
39	Butenes, mixed	Butylenes (mixed)
40	2-Butoxyethanol	Butyl Cellosolve
41	2-Butyne-1,4-diol	--
42	Carbamic acid, monoammonium salt ^a	--
43	Carbon disulfide	--
44	Carbonic dichloride	Phosgene
45	Chlorobenzene, mono-	--
46	2-Chloro-1,3-butadiene ^a	Chloroprene
47	Chlorodifluoromethane	Freon 22
48	Chloroethane	Ethyl chloride
49	Chloroethene	Vinyl chloride
50	6-Chloro-N-ethyl-N'-(1-methylethyl)-1,3,5-triazine-2,4-diamine	(1) 2-Chloro-4-(ethylamino)-6-(isopropylamino)-s-triazine (2) Atrazine
51	Chloromethane	Methyl chloride
52	(Chloromethyl) benzene	(1) Benzyl chloride (2) α -Chlorotoluene
53	(Chloromethyl) oxirane	Epichlorohydrin
54	1-Chloro-4-nitrobenzene	(1) p-Chloronitrobenzene (2) p-Nitrochlorobenzene
55	2-Chloro-1-propanol ^b	(1) 2-Chloropropyl alcohol (2) Propylene chlorohydrin

(See footnotes at end of table)

(continued)

TABLE H-1 (continued)

Chemical number	Chemical name	Common name
56	3-Chloro-1-propene	(1) 3-Chloropropene (2) Allyl chloride
57	Coconut oil acids, sodium salt ^a	--
58	Cyclohexane	Hexahydrobenzene
60	Cyclohexane, oxidized	--
61	Cyclohexanol	(1) Hexalin (2) Hexahydrophenol
62	Cyclohexanone	Pimelic ketone
63	Cyclohexanone oxime	--
64	1,3-Cyclopentadiene ^a	--
65	Cyclopropane	Trimethylene
66	1,2-Dibromoethane	(1) Ethylene dibromide (2) Ethylene bromide
67	Dibutanized aromatic concentrate ^a	--
68	1,4-Dichloro-2-butene	1,4-Dichlorobutene
69	3,4-Dichloro-1-butene	--
70	Dichlorodifluoromethane	Freon 12
71	Dichlorodimethylsilane	Dimethyldichlorosilane
72	1,2-Dichloroethane	(1) Ethylene chloride (2) Ethylene dichloride
73	1,1-Dichloroethene	Vinylidene chloride
74	Dichlorofluoromethane	Freon 21
75	Dichloromethane	Methylene chloride
76	1,3-Dichloro-2-propanol ^a	Dichlorohydrin

(See footnotes at end of table)

(continued)

TABLE H-1 (continued)

Chemical number	Chemical name	Common name
77	Diethylbenzene	--
78	1,3-Diisocyanato-2-(and 4-) methylbenzene (80/20 mixture)	Toluene-2,4-(and 2,6-) diisocyanate (80/20 mixture)
79	Dimethylbenzenes (mixed)	Xylenes (mixed)
80	1,2-Dimethylbenzene	o-Xylene
81	1,3-Dimethylbenzene	m-Xylene
82	1,4-Dimethylbenzene	p-Xylene
83	1,1-Dimethylethyl hydroperoxide ^a	--
84	2,6-Dimethylphenol ^a	(1) m-Xylenol (2) 2,6-Xylenol
85	1-Dodecene	(1) Dodecene (2) Tetrapropylene
86	Dodecylbenzene, linear	Alkylbenzene
87	Dodecylbenzene, nonlinear	--
88	Dodecylbenzenesulfonic acid	--
89	Dodecylbenzenesulfonic acid, sodium salt	--
90	Ethane ^a	(1) Dimethyl (2) Dimethyl
91	1,2-Ethanediol	Ethylene glycol
92	2,2'-(1,2-Ethanediylbis (oxy)) bisethanol	Triethylene glycol
93	Ethanol	Ethyl alcohol
94	Ethene	(1) Ethylene (2) Ethyl (3) Olefiant gas

(See footnotes at end of table)

(continued)

TABLE H-1 (continued)

Chemical number	Chemical name	Common name
95	Ethenone	Ketene
96	Ethenylbenzene	Styrene
97	2-Ethoxyethanol	(1) Ethylene glycol monoethyl ether (2) Cellosolve
98	2-Ethoxyethyl acetate	(1) Ethylene glycol monoethyl ether acetate (2) Cellosolve acetate
99	Ethylbenzene	--
101	2-Ethylhexanal ^a	--
102	2-Ethyl-1-hexanol	2-Ethylhexyl alcohol
103	(2-Ethylhexyl) amine	--
104	Ethylmethylbenzene ^a	--
105	6-Ethyl-1,2,3,4-tetrahydro-9,10-anthracenedione	--
106	Ethyne	(1) Acetylene (2) Ethine
107	Fatty acids, tall oil, sodium salt ^a	--
108	Formaldehyde	(1) Formalin (solution) (2) Methanal (gas)
109	2,5-Furandione	Maleic anhydride
110	D-Glucitol	Sorbitol
111	Heptane	n-Heptane
112	Heptenes (mixed)	--
113	Hexadecyl chloride ^a	--
114	Hexahydro-2H-azepin-2-one	Caprolactam

(See footnotes at end of table)

(continued)

TABLE H-1 (continued)

Chemical number	Chemical name	Common name
115	Hexane	--
116	1,6-Hexanediamine	Hexamethylene diamine
117	1,6-Hexanediamine adipate	(1) Hexamethylene diamine adipate (2) Nylon salt
118	1,6-Hexanedinitrile	(1) Adiponitrile (2) 1,4-Dicyanobutane
119	Hexanedioic acid	Adipic acid
120	2-Hexenedinitrile ^a	1,4-Dicyano-1-butene
121	3-Hexenedinitrile ^a	(1) 1,4-dicyanobutene (2) Dihydromucononitrile (3) 1,4-Dicyano-2-butene
122	Hydrocyanic acid ^b	Hydrogen cyanide
123	4-hydroxy-4-methyl-2-pentanone	Diacetone alcohol
124	2-Hydroxy-2-methylpropanenitrile	(1) Acetone cyanohydrin (2) 2-Methylactonitrile
125	2-Hydroxy-1,2,3-propanetricarboxylic acid	Citric acid
126	2,2'-Iminobisethanol	(1) Diethanolamine (2) 2,2'-Aminodiethanol
127	1,3-Isobenzofurandione	Phthalic anhydride
128	Isodecanol ^b	Isodecyl alcohol
129	Linear alcohols, ethoxylated, mixed	--
130	Linear alcohols, ethoxylated and sulfated, sodium salt, mixed	--
131	Linear alcohols, sulfated, sodium salt, mixed ^a	--

(See footnotes at end of table)

(continued)

TABLE H-1 (continued)

Chemical number	Chemical name	Common name
132	Methane ^b	--
133	Methanol	(1) Methyl alcohol (2) Wood alcohol
134	2-Methoxyethanol ^a	(1) Ethylene glycol mono-methyl ether (2) Methyl Cellosolve
135	Methylbenzene	Toluene
136	4-Methyl-1,3-benzenediamine	(1) Toluene-2,4-diamine (2) 2,4-Diaminotoluene (3) 2,4-Tolylenediamine
137	ar-Methylbenzenediamine	--
138	2-Methyl-1,3-butadiene	Isoprene
139	2-Methylbutane	Isopentane
140	2-Methyl-2-butene	Amylene
141	2-Methylbutenes, mixed	Amylenes, mixed
142	1-Methyl-2,4-dinitrobenzene (and 2-Methyl-1,3-dinitrobenzene)	2,4- (and 2,6-) Dinitrotoluene
143	1-Methyl-2,4-dinitrobenzene	2,4-Dinitrotoluene
144	(1-Methylethyl) benzene	Cumene
145	4,4'-(1-Methylethylidene) bisphenol	(1) 4,4'-Isopropylidenediphenol (2) Bisphenol A
146	Methyloxirane	Propylene oxide
147	2-Methylpentane ^a	Isohexane
148	4-Methyl-2-pentanone	(1) Isopropyl acetone (2) Methyl Isobutyl ketone

(See footnotes at end of table)

(continued)

TABLE H-1 (continued)

Chemical number	Chemical name	Common name
149	1-Methyl-1-phenylethyl hydroperoxide	Cumene hydroperoxide
150	2-Methylpropanal	(1) Isobutyraldehyde (2) Isobutylaldehyde
151	2-Methylpropane	Isobutane
152	2-Methyl-1-propanol	Isobutyl alcohol
153	2-Methyl-2-propanol	(1) tert-Butyl alcohol (2) t-Butanol
154	2-Methyl-1-propene	(1) Isobutylene (2) 2-Methylpropene
155	2-Methyl-2-propenenitrile ^a	Methacrylonitrile
156	2-Methyl-2-propenoic acid, methyl ester	(1) Methacrylic acid methyl ester (2) Methyl methacrylate
157	1-Methyl-2-pyrrolidinone	1-Methyl-2-pyrrolidone
158	Naphthalene	(1) Naphthene (2) Naphthalin
159	2,2',2''-Nitrilotrisethanol	(1) Triethanolamine (2) Triethylamine
160	Nitrobenzene	Nitrobenzol
161	1-Nonanol	(1) n-Nonanol (2) Nonyl alcohol
162	1-Nonene	Tripropylene
163	Nonylphenol	--
164	Nonylphenol, ethoxylated	--
165	Octene	--

(See footnotes at end of table)

(continued)

TABLE H-1 (continued)

Chemical number	Chemical name	Common name
166	Oil-soluble petroleum sulfonate, calcium salt	--
167	Oil-soluble petroleum sulfonate, sodium salt	--
168	Oxirane	Ethylene oxide
169	2,2'-Oxybisethanol	Diethylene glycol
170	Pentane ^a	n-Pentane
171	3-Pentenitrile	--
172	Pentenes, mixed	--
173	Phenol	(1) Carbofic acid (2) Hydroxybenzene
174	1-Phenylethyl hydroperoxide	--
175	Propanal	Propionaldehyde
176	Propane	Dimethyl methane
177	1,2-Propanediol	Propylene glycol
178	Propanenitrile ^a	(1) Propionitrile (2) Ethyl cyanide
179	1,2,3-Propanetriol	(1) Glycerol (2) Glyceryl (3) Glycerin
180	Propanoic acid ^a	Propionic acid
181	1-Propanol	Propyl alcohol
182	2-Propanol	Isopropyl alcohol
183	2-Propanone	(1) Acetone (2) Dimethyl ketone
184	1-Propene	Propylene

(See footnotes at end of table)

(continued)

TABLE H-1 (continued)

Chemical number	Chemical name	Common name
185	2-Propenenitrile	Acrylonitrile
186	2-Propenoic acid	Acrylic acid
187	2-Propenoic acid, butyl ester	Butyl acrylate
188	2-Propenoic acid, ethyl ester	Ethyl acrylate
189	Propylbenzene	Phenylpropane
190	Sodium cyanide ^a	Cyanogran
191	Tallow acids, potassium salt ^a	--
192	Tallow acids, sodium salt ^a	--
193	Tetrabromomethane ^a	Carbontetrabromide
194	Tetrachloroethene	(1) Tetrachloroethylene (2) Perchloroethylene
195	Tetrachloromethane	Carbon tetrachloride
196	Tetraethylplumbane	Tetraethyl lead
197	1,2,3,4-Tetrahydrobenzene	Cyclohexene
198	Tetrahydrofuran	THF
199	Tetra (methyl-ethyl) plumbane	Tetra (methyl-ethyl) lead
200	Tetramethylplumbane ^a	Tetramethyl lead
201	1,3,5-Triazine-2,4,6-triamine ^a	(1) Melamine (2) 2,4,6-Triamino-s-triazine
202	1,1,1-Tribromo-2-methyl-2-propanol	(1) Tribromo-t-butyl alcohol (2) Acetone-bromoform (3) Brometone
203	1,1,1-Trichloroethane	Methyl chloroform
204	1,1,2-Trichloroethane	Vinyl trichloride

(See footnotes at end of table)

(continued)

TABLE H-1 (continued)

Chemical number	Chemical name	Common name
205	Trichloroethene	Trichloroethylene
206	Trichlorofluoromethane	(1) Freon 11 (2) Fluorotrichloromethane
207	Trichloromethane	Chloroform
208	2,4,6-Trichloro-1,3,5-triazine	(1) Cyanuric chloride (2) 2,4,6-Trichloro-s-triazine
209	1,1,2-Trichloro-1,2,2-trifluoroethane	(1) Trichlorotrifluoroethane (2) Fluorocarbon 113
210	2,6,6-Trimethylbicyclo-[3.1.1]hept-2-ene	α -Pinene
211	Urea ^a	(1) Carbamide (2) Carbonyldiamide
212	Urea ammonium nitrate ^a	--
213	3-Hydroxybutyraldehyde ^b	(1) Aldol (2) Acetaldehyde
214	2-Butanal ^b	(1) Crotonaldehyde (2) β -Methylacrolein
215	2-Butenoic acid ^b	Crotonic acid
216	1,3,5,7-Tetraazatricyclo-[3.3.1.1 ^{3,7}]decane	(1) Hexamine (2) Hexamethylene tetraamine
217	6-Methyl heptanol ^a	(1) Isooctyl alcohol (2) Isooctanol
220	Methanamine	Methylamine
221	N-Methylmethanamine ^a	Dimethylamine
222	4-Methyl-3-penten-2-one	Mesityl oxide
223	Benzotrichloride ^a	--

(See footnotes at end of table)

(continued)

TABLE H-1 (continued)

Chemical number	Chemical name	Common name
224	1-Bromobutane ^a	--
225	2-Chloroethanol ^a	--
226	Ethanamine ^a	--
227	Ethyl-Δ-nonylate ^a	--
228	Ethylsulfate ^a	--
230	Isononanol ^a	--
232	Propiolacetone ^a	--
234	Tribromomethane ^a	Bromoform
235	1,1,2,2-Tetrachloroethane ^a	--
236	Iodomethane ^a	Methyl iodide
237	Methyl t-butyl ether	MTBE
238	Alcohols, C-12 or higher, unmixed	--
239	Tert-Butyl hydroporoxide	--
240	Chloroacetic acid	--
248	Carbon dioxide ^b	--
249	Carbon monoxide ^b	--
250	1,3-Dichloropropane ^b	--
251	Butyric acid ^b	--
252	--	Synthesis gas ^b
254	Diisobutene ^b	--
257	Cyanogen chloride ^b	--

^aNon-reactor process chemicals not affected by the standards.

^bIntermediate chemicals used in roll-through price analysis.

that are not used in production by reactor processes. These 51 numbers are, 7, 13, 19, 23, 24, 31, 42, 46, 57, 64, 67, 76, 83, 84, 90, 101, 104, 107, 113, 120, 121, 131, 134, 147, 155, 167, 170, 178, 180, 190, 191, 192, 193, 200, 201, 210, 211, 212, 217, 221, 223, 224, 225, 226, 227, 228, 230, 232, 234, 235, 236. Third, chemicals numbered above 212 are not in alphabetic order. These chemicals were added to the original alphabetic list to more completely define the SOCOMI industry.

H.2 SCREENING ANALYSIS INPUT FILES

The two input files used in the main screening analysis program are presented in Tables H-2 and H-3. These two files are slightly different in that the first represents the reasonable worst-case scenario and the second represents the more likely case scenario. Letter codes head each column in the tables, defining the data as follows:

Reasonable Worst-Case Input File (Table H-2)

- A Chemical number. This is the identification number assigned to each chemical in Table H-1. These numbers are used throughout the computer programs described in this appendix.
- B Capacity in gigagrams. For the reasonable worst-case scenario, this figure is the smallest existing plant size producing the chemical. When no chemical-specific data is available, the median value of all chemical's smallest existing size is used as a default. That median value is 23 Gg.
- C Priority code. This code is a mechanism by which the program calculates rolled-through costs in an order that follows the chain of production among chemicals. Each chemical is assigned a priority code, 1 being the highest, then 2 and so on. The program calculates control costs first for input chemicals and then for derivative chemicals on the list according to their priority number. This code does not signify plant characteristics or relative importance, but is merely a tool for the program in timing its calculations.
- D Number of processes. This is the number of alternative major commercial processes available for the final step in producing the chemical. Each chemical will have the same number of data lines as this number indicates, and each line represents a separate process.
- E Number of inputs. For each process route, this number shows the number of input chemicals used in finding the rolled-through costs. The entries might differ for different processes for the same chemical.

Table H-2 Reasonable Worst-Case Input File

A	B	C	D	E	F	G	F	G	F	G	H	J
001	181.0	02	01	01	94	0.71					75.0	750.7
002	41.0	04	02	01	1	0.77					58.0	148.1
002	41.0	04	02	01	133	0.56					58.0	148.1
003	63.0	06	01	02	2	1.40	95	0.79			90.0	42.7
004	9.0	05	01	02	2	0.54	34	0.71			106.0	36.0
005	181.0	05	01	02	2	0.73	94	0.37			71.0	35.7
006	7.0	05	01	02	2	0.69	93	0.59			95.0	38.1
008	11.0	02	02	01	94	1.18					106.0	0.0
008	11.0	02	02	01	176						106.0	0.0
009	11.0	02	01	01	94	1.29					121.0	0.0
010	37.4	03	01	01	168	0.75					111.0	0.0
011	59.0	04	02	01	160	1.35					84.0	0.0
011	59.0	04	02	01	160	1.47					84.0	0.0
012	3.0	02	02								46.0	44.9
012	3.0	02	02	01	135	1.23					46.0	44.9
014	195.0	03	01	01	82	0.67					77.0	0.0
015	14.0	04	01	02	127	0.39	102	0.70			110.0	35.9
016	5.0	04	01	03	34	0.26	52	0.45	127	0.53	99.0	36.5
017	9.0	04	01	02	9	1.18	127	0.29			107.0	37.4
018	9.0	04	01	02	127	0.34	128	0.75			72.0	37.4
020	227.0	04	01	02	82	0.61	133	0.40			70.0	0.0
021	5.0	03	01	01	12	0.49					112.0	195.7
022	5.0	04	01	01	21	1.00					104.0	0.0
025	11.0	05	01	02	1	0.40	108	1.22			156.0	37.7
026	20.0	02	03	01	29	1.93					67.0	0.0
026	20.0	02	03	01	39	1.35					67.0	0.0
026	20.0	02	03								67.0	0.0
027	3.0	02	02	01	29	1.80					67.0	44.9
027	3.0	02	02								67.0	44.9
028	36.0	02	01	01	184	0.75					77.0	65.0
029	23.0	01	01								29.0	0.0
030	23.0	01										0.0
032	27.0	06	01	01	41	1.19					172.0	38.8
033	25.0	04	02	01	215	1.21					98.0	38.7
033	25.0	04	02	01	251	1.24	95	0.30			98.0	38.7
034	2.0	03	01	01	28	1.03					70.0	47.3
035	34.0	03	01	01	37	0.90					77.0	61.0
036	36.0	04	01	01	35	1.17					88.0	0.0
037	12.0	02	01	01	94						66.0	0.0
038	23.0	03	01	01	37	1.15					38.0	0.0
039	11.0	01	01								42.0	0.0
040	25.0	04	01	02	34	0.90	168	0.59			73.0	38.7
041	23.0	05	01	02	106	0.43	108	1.00			319.0	35.9
043	5.0	02	01	01	132	0.23					37.0	0.0
044	11.0	03	01	01	249						79.0	0.0

Table H-2 Continued.

A	B	C	D	E	F	G	F	G	F	G	H	J
045	23.0	03	01	01	12	0.82					84.0	384.6
047	23.0	06	01	01	207	1.10					51.0	0.0
048	34.0	03	02	01	93	0.75					53.0	365.3
048	34.0	03	02	01	94	0.49					53.0	365.3
049	136.0	03	01	01	72	1.65					40.0	0.0
050	11.0	04	02	01	132	0.33					44.0	0.0
051	11.0	04	02	01	133	0.68					44.0	364.5
052	9.0	02	01	01	135	0.80					92.0	374.9
053	100.0	03	01	01	56	1.08					181.0	368.6
054	45.0	04	01	01	45	0.80					174.0	409.2
055		02	01	01	184	0.64						0.0
056	53.0	02	01	01	184	0.74					126.0	0.0
058	35.0	03	01	01	12	0.93					55.0	0.0
060	45.0	04	01	01	58	0.94					121.0	0.0
061	23.0	06	02	01	58	1.20					137.0	0.0
061	23.0	06	02	01	173	0.98					137.0	0.0
062	9.0	07	02	01	61	0.84					132.0	53.4
062	9.0	07	02	01	173	0.98					132.0	53.4
063	37.4	08	01	01	62	1.24					98.0	0.0
065	23.0	03	01	01	250						120.0	67.8
066	23.0	02	01	01	94	0.17					84.0	381.1
068	23.0	04	01	01	69	1.52					101.0	615.1
069	23.0	03	01	01	26	0.94					101.0	381.1
070	23.0	04	01	01	195	1.33					163.0	0.0
071	23.0	05	01	01	50	1.12					462.0	0.0
072	68.0	02	01	01	94	0.31					31.0	369.6
073	45.0	04	02	01	49	0.68					61.0	365.2
073	45.0	04	02	01	204	1.38					61.0	365.2
074	23.0	06	01	01	207	1.45					157.0	0.0
075	27.0	05	02	01	50	0.61					53.0	0.0
077	27.0	04	01	02	94	0.30	99	1.12			218.0	37.0
078	18.0	04	01	02	44	1.43	137	0.88			205.0	0.0
079	23.0	01	01								46.0	0.0
080	11.0	02	01	01	79	4.55					51.0	0.0
081	79.0	02	01	01	79	2.50					77.0	0.0
082	27.0	02	01	01	79	5.56					64.0	0.0
085	8.0	02	01	01	184	1.27					33.0	0.0
086	18.0	03	01	02	12	0.35	85	0.76			101.0	36.4
087	102.0	03	01	02	12	0.35	85	0.76			101.0	41.5
088	14.0	04	01	01	86	0.75					106.0	285.5
089	23.0	05	01	01	88	0.70					93.0	0.0
091	23.0	03	01	01	168	0.75					73.0	0.0
092	1.0	03	01	01	168	0.90					97.0	0.0
093	75.0	02	01	01	94	0.61					57.0	0.0
094	45.0	01	01								53.0	0.0
095	32.5	05	01	01	2	1.59					149.0	0.0
096	54.0	04	01	01	99	1.13					77.0	176.1
097	23.0	03	01	02	93	0.57	168	0.54			93.0	38.5

Table H-2 Continued.

A	B	C	D	E	F	G	F	G	F	G	H	J
098	9.0	05	01	02	2	0.48	97	0.76			115.0	37.4
099	16.0	03	01	02	12	0.76	94	0.28			71.0	36.3
102	25.0	03	01	01	28	1.23					88.0	0.0
103	27.0	04	01	01	102	1.44					111.0	37.0
105	25.0	04	01	02	99	0.64	127	0.90			139.0	83.0
106	5.0	02	02	01	132	4.10					121.0	0.0
106	5.0	02	02	01	176	2.82					121.0	0.0
108	27.0	04	01	01	133	1.19					20.0	0.0
109	5.0	03	02	01	12	1.33					99.0	0.0
109	5.0	03	02	01	39	2.12					99.0	0.0
110	5.0	01	01								101.0	38.1
111	5.0	01									42.0	0.0
112	14.0	02	02	01	39	0.79					34.0	0.0
112	14.0	02	02	01	184	1.70					34.0	0.0
114	159.0	08	01	01	62	0.92					190.0	0.0
115	27.0	01									40.0	0.0
116	23.0	07	01	01	118	0.93					92.0	38.8
117	9.0	08	01	02	116	0.63	120	0.80			181.0	37.4
118	23.0	06	03	01	27	0.72					100.0	129.5
118	23.0	06	03	01	120	1.93					100.0	129.5
118	23.0	06	03	01	185	1.09					100.0	129.5
119	14.0	07	02	01	58	0.78					132.0	173.1
119	14.0	07	02	01	61	0.65					132.0	173.1
122		02	01	01	132	0.79					19.0	0.0
123	25.0	06	01	01	183	1.01					112.0	38.7
124	23.0	06	01	01	183	0.60						0.0
125	11.0	01									181.0	0.0
126	159.0	03	01	01	168	0.88					106.0	0.0
127	36.0	03	02	01	80	0.98					77.0	0.0
127	36.0	03	02	01	158	1.25					77.0	0.0
128		03	01	01	162	1.25					83.0	0.0
129	23.0	03	01	02	9	0.93	168	0.22			84.0	38.5
130	113.4	04	01	01	129	0.87					114.0	0.0
132		01	01									0.0
133	174.0	03	01	01	132	0.56					24.0	505.3
135	27.0	01	01								269.0	0.0
136	23.0	03	01	01	143	1.57					165.0	43.7
137	23.0	03	01	01	143	3.57					100.0	43.7
138	23.0	02	02	01	139						53.0	79.7
138	23.0	02	02	01	141	1.30					53.0	79.7
139	5.0	01	01								71.0	0.0
140	2.3	01										0.0
141	23.0	01	01									0.0
142	17.0	02	01	01	135	0.53					201.0	105.0
143	34.0	02	01	01	135	0.53					196.0	201.6
144	54.0	03	01	02	12	0.72	184	1.17			53.0	0.0
145	45.0	06	01	02	173	0.88	183	0.28			134.0	0.0
146	200.0	03	02	01	55	1.47					99.0	169.6

Table H-2 Continued.

A	B	C	D	E	F	G	F	G	F	G	H	J
146	200.0	03	02	02	151	2.60	184	0.78			99.0	169.6
148	7.0	08	01	01	183	1.29					108.0	38.5
149	2.3	04	01	01	144	0.80						0.0
150	7.0	02	01	01	184	0.75					95.0	42.5
151	23.0	02	01	01	29	1.15					22.0	0.0
152	7.0	03	01	01	28	1.03					66.0	38.5
153	2.3	02	01	01	154	0.92					159.0	36.9
154	7.0	01	01								15.0	0.0
156	54.0	06	01	03	122	0.27	133	0.32	183	0.58	137.0	49.7
157	127.0	07	01	01	32	0.72					260.0	0.0
158	34.0	01	01								48.0	0.0
159	127.0	03	01	01	168	0.93					108.0	0.0
160	34.0	03	01	01	12	0.65					75.0	35.8
161	21.5	02	01	01	254						84.0	54.1
162	11.0	02	01	01	184	1.21					37.0	0.0
163	5.0	06	01	02	162	0.76	173	0.46			112.0	0.0
164	25.0	07	01	02	163	0.96	168	0.19			114.0	0.0
165	11.0	02	01	01	39						97.0	0.0
166	23.0	01	01								108.0	0.0
168	50.0	02	01	01	94	1.00					70.0	418.5
169	2.0	03	01	01	168	0.84					70.0	0.0
171	23.0	03	01	01	26	0.96					100.0	0.0
172	27.0	1										0.0
173	34.0	05	01	01	149	1.79					79.0	0.0
174	18.0	04	01	01	99	1.28					100.0	214.8
175	21.5	02	01	01	94	0.60					79.0	54.1
176	23.0	01	01								22.0	0.0
177	23.0	04	01	01	146	0.77					97.0	0.0
179	18.0	04	02	01	53	1.15					176.0	0.0
179	18.0	04	02								176.0	0.0
181	29.0	03	01	01	175	1.40					92.0	45.2
182	23.0	02	01	01	184	0.85					73.0	53.2
183	25.0	05	02	01	144	2.30					66.0	0.0
184	32.5	01	01								46.0	0.0
185	113.0	02	01	01	184	1.25					99.0	0.0
186	18.0	02	01	01	184	0.83					115.0	0.0
187	9.0	04	01	02	34	0.58	186	0.57			150.0	37.4
188	9.0	03	02	02	93	0.48	106	0.32			123.0	49.7
188	9.0	03	02	02	93	0.51	186	0.76			123.0	49.7
189	227.0	03	01	02	12	0.93	184	0.50			91.0	50.8
194	23.0	03	03	01	132	0.21					46.0	0.0
195	4.0	03	03	01	132	0.11					42.0	0.0
196	36.0	04	01	01	48	1.19					606.0	37.5
197	23.0	07	01	01	61	1.74					91.0	67.8
198	23.0	07	01	01	32	1.31					225.0	67.8
199	27.0	04	01	01	48	0.73					364.0	37.0
202	23.0	06	01	01	183	0.27					100.0	381.1
203	91.0	05	01	01	73	0.73					77.0	0.0

Table H-2 Continued.

A	B	C	D	E	F	G	F	G	F	G	H	J
204	5.0	03	01	01	72	0.81					75.0	3.7
205	54.0	03	01	01	72	0.74					68.0	367.7
206	23.0	04	01	01	195	1.17					141.0	0.0
207	16.0	05	02	01	50	0.43					68.0	0.0
208	5.0	04	01	01	257						319.0	372.9
209	5.0	04	01	01	194	0.98					194.0	0.0
213		3	01	01	1	1.11						0.0
214		3	01	01	213	1.40						0.0
215		3	01	01	214	0.90						0.0
216	4.0	05	01	01	108	1.32					112.0	35.6
220	37.4	04	01	01	133	1.05					115.0	0.0
222	5.0	07	01	01	183	1.32					101.0	45.7
237	25.0	04	01	02	133	0.36	154	0.64			40.0	0.0
238	11.5	02	01	01	9	1.00					121.0	0.0
239	23.0	03	01	01	153	0.95					100.0	67.8
240	2.0	05	01	01	2	0.69					123.0	371.8
248		02	01	01	132							0.0
249		02	01	01	132							0.0
250		02	01	01	176							0.0
251		3	01	01	28	0.91						0.0
252		02	01	01	132							0.0
254		01	01									0.0
257		03	01	01	122							0.0

Table H-3 More Likely Case Input File

A	B	C	D	E	F	G	F	G	F	G	H	K
001	181.0	02	01	01	94	0.71					75.0	0.0
002	41.0	04	02	01	1	0.77					58.0	0.0
002	41.0	04	02	01	133	0.56					58.0	0.0
004	23.0	05	01	02	2	0.54	34	0.71			106.0	37036.0
005	193.0	05	05	02	2	0.73	94	0.37			71.0	35776.0
006	15.0	05	01	02	2	0.69	93	0.59			95.0	41256.0
009		02	01	01	94	1.29					121.0	0.0
010	11.0	03	01	01	168	0.75					111.0	0.0
011	59.0	04	02	01	160	1.35					84.0	0.0
011	59.0	04	02	01	160	1.47					84.0	0.0
012	3.0	02	02								46.0	0.0
012	3.0	02	02	01	135	1.23					46.0	0.0
015	14.0	04	01	02	127	0.39	102	0.70			110.0	0.0
018	2.0	04	01	02	127	0.34	128	0.75			72.0	0.0
021	4.0	03	01	01	12	0.49					112.0	0.0
022	5.0	04	01	01	21	1.00					104.0	0.0
028	36.0	02	01	01	184	0.75					77.0	0.0
029		01	01								29.0	0.0
034	2.0	03	01	01	28	1.03					70.0	0.0
040	23.0	04	01	02	34	0.90	168	0.59			73.0	0.0
043	5.0	02	01	01	132	0.23					37.0	0.0
045	68.0	03	01	01	12	0.82					84.0	411492.0
051	11.0	04	02	01	133	0.68					44.0	0.0
052	36.0	02	01	01	135	0.80					92.0	386904.0
054	18.0	04	01	01	45	0.80					174.0	381820.0
055		02	01	01	184	0.64						0.0
058	35.0	03	01	01	12	0.93					55.0	0.0
061	23.0	06	02	01	58	1.20					137.0	0.0
061	23.0	06	02	01	173	0.98					137.0	0.0
065	18.0	03	01	01	250						120.0	61270.0
070		04	01	01	195	1.33					163.0	0.0
072	68.0	02	01	01	94	0.31					31.0	0.0
073	45.0	04	02	01	49	0.68					61.0	0.0
073	45.0	04	02	01	204	1.38					61.0	0.0
077	18.0	04	01	02	94	0.30	99	1.12			218.0	36392.0
085	8.0	02	01	01	184	1.27					33.0	0.0
086	18.0	03	01	02	12	0.35	85	0.76			101.0	0.0
087	16.0	03	01	02	12	0.35	85	0.76			101.0	0.0
088	18.0	04	01	01	86	0.75					106.0	0.0
089		05	01	01	88	0.70					93.0	0.0
091	23.0	03	01	01	168	0.75					73.0	0.0
092	1.0	03	01	01	168	0.90					97.0	0.0
093	75.0	02	01	01	94	0.61					57.0	0.0
094	45.0	01	01								53.0	0.0
096	54.0	04	01	01	99	1.13					77.0	0.0

Table H-3 Continued.

A	B	C	D	E	F	G	F	G	F	G	H	K
097	23.0	03	01	02	93	0.57	168	0.54			93.0	0.0
099	318.0	03	01	02	12	0.76	94	0.28			71.0	56332.0
105		04	01	02	99	0.64	127	0.90			139.0	0.0
106	5.0	02	02	01	132	4.10					121.0	0.0
106	5.0	02	02	01	176	2.82					121.0	0.0
119	236.0	07	02	01	58	0.78					132.0	396356.0
119	236.0	07	02	01	61	0.65					132.0	396356.0
122		02	01	01	132	0.79					19.0	0.0
123	7.0	06	01	01	183	1.01					112.0	35780.0
126		03	01	01	168	0.88					106.0	0.0
127	36.0	03	02	01	80	0.98					77.0	0.0
127	36.0	03	02	01	158	1.25					77.0	0.0
128		03	01	01	162	1.25					83.0	0.0
129		03	01	02	9	0.93	168	0.22			84.0	0.0
132		01	01									0.0
133	174.0	03	01	01	252						24.0	0.0
135		01	01								269.0	0.0
136		03	01	01	143	1.57					165.0	0.0
137		03	01	01	143	3.57					100.0	0.0
142	17.0	02	01	01	135	0.53					201.0	105019.0
143	80.0	02	01	01	135	0.53					196.0	269986.0
144	54.0	03	01	02	12	0.72	184	1.16			53.0	0.0
146	322.0	03	02	01	55	1.47					99.0	172896.0
146	322.0	03	02	02	151	2.60	184	0.78			99.0	172896.0
149	5.0	04	01	01	144	0.80						0.0
151		02	01	01	29	1.15					22.0	0.0
153	5.0	02	01	01	154	0.92					159.0	38832.0
154	7.0	01	01								15.0	0.0
156	95.0	06	01	03	122	0.27	133	0.32	183	0.58	137.0	59394.0
158	34.0	01	01								48.0	0.0
159		03	01	01	168	0.93					108.0	0.0
160	153.0	03	01	01	12	0.65					75.0	39256.0
162	11.0	02	01	01	184	1.21					37.0	0.0
163	5.0	06	01	02	162	0.76	173	0.46			112.0	0.0
164		07	01	02	163	0.96	163	0.19			114.0	0.0
168	204.0	02	01	01	94	1.00					70.0	1174592.0
169	2.0	03	01	01	168	0.84					70.0	0.0
173	34.0	05	01	01	149	1.79					79.0	0.0
174	18.0	04	01	01	99	1.28					100.0	214784.0
176		01	01								22.0	0.0
177	23.0	04	01	01	146	0.77					97.0	0.0
182	206.0	02	01	01	184	0.85					73.0	169783.0
183	25.0	05	02	01	144	2.30					66.0	0.0
184		01	01								46.0	0.0
186	18.0	02	01	01	184	0.83					115.0	0.0
187	35.0	04	01	02	34	0.58	186	0.57			150.0	43548.0
188	43.0	03	02	02	93	0.48	106	0.32			123.0	99742.0
188	43.0	03	02	02	93	0.51	186	0.76			123.0	99742.0

Table H-3 Continued.

A	B	C	D	E	F	G	F	G	F	G	H	K
189	18.0	03	01	02	12	0.93	184	0.50			91.0	36392.0
194	48.0	03	03	01	132	1.00					46.0	0.0
195	41.0	03	03	01	132	0.11					42.0	0.0
204	45.0	03	01	01	72	0.81					75.0	390885.0
206		04	01	01	195	1.17					141.0	0.0
208	18.0	04	01	01	257						319.0	378900.0
209	5.0	04	01	01	194	0.98					194.0	0.0
239	23.0	03	01	01	153	0.95					100.0	67840.0
248		02	01	01	132	1.00						0.0
250		02	01	01	176							0.0
252		02	01	01	132							0.0
257		03	01	01	122							0.0

- F Input ID. The number in the first F column designates the ID number of one input used in the particular process. If none of the chemicals listed in Table H-1 is an input, this column is blank.
- G Input ratio. This decimal number in the first G column indicates the kilogram amount of the first F-column chemical used per kilogram of produced chemical.
- The program allows for up to three chemical inputs for a process. Columns F and G therefore are repeated for processes involving more than one chemical input. If no other inputs are used this space is blank.
- H Chemical price. The price is a recent market price given in cents per kilogram (\$/kg) in 1982 dollars when no current price is available the weighted average price for all chemicals, 46¢/kg, is used.
- J Control cost. The cost is the annual cost of control based on reasonable worst-case assumptions in thousands of 1982 dollars.

More Likely Case Input File (Table H-3)

Columns are as described above except as follows:

- B Capacity in gigagrams. For this case the capacity is the current median size process unit, which is assumed to be the size of the unit(s) that will be built by 1990 to accommodate growth. This size is equal to the current median plant size.
- K Control cost. The cost is the annual cost of control based on more likely case assumptions, in 1982 dollars.

H.3 SCREENING ANALYSIS PROGRAM

The program used in the screening analysis to compute the price increases is shown in Figure H-1. Written in the Pascal language, the program contains a series of arrays in which data manipulation takes place. For each variable described above, an array of values representing the specific data for all 173 affected chemicals and the 16 intermediate chemicals used in several processes is read from the input files (Statement A in Figure H-1). Statements execute all subsequent commands on the entire data set, chemical by chemical. Important statements in the program are labeled in Figure H-1, and their function is described below.

- A This command reads the values from the input files and assigns the numbers to variable arrays. The calculations are performed on these entire columns of numbers, each column representing a different variable.

```

program maxcost;

const max = 215;
      Ricost = 0;
var prod, hal, prior, num_prod, num_inpt, hv: array[1..max] of integer;
    cap, frmult, mpr, cost_inc, to_cost1, infl: array[1..max] of real;
    inpt_id: array[1..max, 1..3] of integer;
    inpt_rat: array[1..max, 1..3] of real;
    not_big: array[1..max] of boolean;
    infcat: array[1..8] of integer;
    percent: array[1..8] of real;
    category, num_hi, num_lo, h, l, j, k, l, hold: integer;
    y, z, ninc, hvc, fre, frcap, frop, maxx: real;
    maxcost: array[1..3] of real;
    more: boolean;
    infile1, outfile: text;

begin
    reset ('a-vscharin', infile1);
    rewrite ('a-deltapout', outfile);
    for i := 1 to max do
    begin
        cost_inc[i] := 0.0;
        infl[i] := 0.0;
        not_big[i] := true;
    end;
    for i := 1 to 8 do
    begin
        infcat[i] := 0;
    end;
    for i := 1 to 3 do
    begin
        maxcost[i] := 0.0;
    end;
    ninc := 1.0;
    category := 1;
    num_hi := 0;
    num_lo := 0;
    hold := 0;
    hvc := 0.0;
    fre := 0.0;
    frcap := 0.0;
    frop := 0.0;
    maxx := 0.0;
    more := false;
    { read and process input file }
    for i := 1 to (max - 1) do
    begin
        readln (infile1, prod[i], cap[i], prior[i], num_prod[i],
            num_inpt[i], inpt_id[i,1], inpt_rat[i,1], inpt_id[i,2], inpt_rat[i,2],
            inpt_id[i,3], inpt_rat[i,3], mpr[i], frmult[i], cost1[i]);

```

Figure H-1. Screening analysis program.

```

if cost1[i] > 0.0 then
  tc[i] := cost1[i] + N1cost
else
  tc[i] := cost1[i];
  ( select plant capacities )
B if cap[i] <= 0.0 then cap[i] := 23.0;
  ( select prices )
C if mpr[i] <= 0.0 then mpr[i] := 46.0;
  cost_inc[i] := tc[i]*1000.0;
D if cost_inc[i] < 0.0 then cost_inc[i] := 0.0;
  cost_inc[i] := cost_inc[i]/(cap[i]*10000.0);
end;
( for each product-process listed, the max cost will be
determined. costs will be pyramidally built, i.e.,
starting with priority 2, as priority 1 has
already been determined in the previous loop.)
prod[max] := 999; ( initialize to flush out last value )
for i := 2 to 8 do
begin ( 8 is the highest priority )
  for j := 1 to (max - 1) do
  begin ( looking for priority 1's )
    for k := 1 to 3 do
    begin
      E 1 maxcost[k] := 0.0; ( initializing max eff cost to zero )
        if inpt_rat[j,k] < 0.0 then inpt_rat[j,k] := 0.0;
      end;
        if prior[j] = 1 then
      begin ( must search for max cost of all input materials to
        this product process identified in j-loop )
        for k := 1 to num_inpt[j] do
        begin
          more := true;
          while more do
          begin
            for l := 1 to max do
            begin ( trying to find the input materials one at a time )
              if prod[l] = inpt_id[j,k] then
              begin ( a match has been made of an input to a listed product
                process, test to see if its the highest cost found thus
                far for this particular input )
                E 2 if cost_inc[l] >= maxcost[k] then maxcost[k] := cost_inc[l];
                  end;
                  else if prod[l] > inpt_id[j,k] then more := false;
                  ( no more matches to this product may be made )
                end;
              end;
            end;
          ( compute the effective cost inc for this product process )
          cost_inc[j] := cost_inc[j] + maxcost[1] * inpt_rat[j,1] +
            maxcost[2] * inpt_rat[j,2] +
            maxcost[3] * inpt_rat[j,3];
          E 3
        end;
      end;
    end;
  end;
end;

```

Figure H-1 (continued)

```

[ next the inflation factors must be calculated and
  the worst case-cost processes written out ]
writeln (outfile);
writeln (outfile);
writeln (outfile, '
                                highest cost production processes');
writeln (outfile);
writeln (outfile, ' chem proc    1982 mkt $ ',
          ' eff est inc  inflation',
          ' capacity annual cost  ');

writeln(outfile);
maxx := cost_inc[1];
hold := prod[1];
h := 1;
for i := 1 to max do
begin
  [ compute inflation & select & print the highest cost product
    processes. flag the highest and lowest cost products as such ]
  F  if ((hal[i] > 0) or ((hal[i] = 0) and (prior[i] > 1))) and
      (mpr[i] > 0.0) then infl[i] := (cost_inc[i] / mpr[i]) * 100.0;
      if i > 1 then
      begin
        [ must process at least two recs to make comparison ]
        if prod[i] > hold then
          begin
            [ recs for the product being held have been exhausted &
              the highest cost one now held must be written out &
              replaced with the new record now coming in ]
            writeln (outfile, prod[h]:10, mpr[h]:12:2,
                    cost_inc[h]:13:2, infl[h]:11:2, cap[h]:13:4,
                    tc[h]:12:1);
            not big[h] := false;
            num_hi := num_hi + 1;
            hold := prod[i];
            maxx := cost_inc[i];
            if infl[h] = 0.0 then infcat[1] := infcat[1] + 1;
            if (infl[h] > 0.0) and (infl[h] < 2.0) then
              infcat[2] := infcat[2] + 1;
            if (infl[h] > 2.0) and (infl[h] < 3.0) then
              infcat[3] := infcat[3] + 1;
            if (infl[h] > 3.0) and (infl[h] < 5.0) then
              infcat[4] := infcat[4] + 1;
            if (infl[h] >= 5.0) and (infl[h] < 10.0) then
              infcat[5] := infcat[5] + 1;
            if (infl[h] >= 10.0) and (infl[h] < 15.0) then
              infcat[6] := infcat[6] + 1;
            if (infl[h] >= 15.0) and (infl[h] < 20.0) then
              infcat[7] := infcat[7] + 1;
            if infl[h] >= 20.0 then infcat[8] := infcat[8] + 1;
            h := i;
          end
        else if cost_inc[i] > maxx then
          begin
            [ switch rec being held to the new higher one ]
            h := i;
            maxx := cost_inc[i];
          end
        end;
      end;
end;

```

Figure H-1 (continued)


```

end;
for i := 1 to 8 do
begin
  percent[i] := (infcat[i]/num_h1)*100;
end;
[ inflation counts will be printed next.]
writeln (outfile);
writeln (outfile);
writeln (outfile);
writeln (outfile, '
      no.    percent');
writeln (outfile, 'chemicals having 0% inflation      = ',
  infcat[1]:10, percent[1]:10:2);
writeln (outfile, 'chemicals having 0.1 to 1.9% inflation = ',
  infcat[2]:10, percent[2]:10:2);
writeln (outfile, 'chemicals having 2.0 to 2.9% inflation = ',
  infcat[3]:10, percent[3]:10:2);
writeln (outfile, 'chemicals having 3.0 to 4.9% inflation = ',
  infcat[4]:10, percent[4]:10:2);
writeln (outfile, 'chemicals having 5.0 to 9.9% inflation = ',
  infcat[5]:10, percent[5]:10:2);
writeln (outfile, 'chemicals having 10.0 to 14.9% inflation = ',
  infcat[6]:10, percent[6]:10:2);
writeln (outfile, 'chemicals having 15.0 to 19.9% inflation = ',
  infcat[7]:10, percent[7]:10:2);
writeln (outfile, 'chemicals having 20% or more inflation = ',
  infcat[8]:10, percent[8]:10:2);
[all those product-processes which are not the
 highest costs will be printed out next ]
writeln (outfile);
writeln (outfile);
writeln (outfile);
writeln (outfile, '
                                     processes not selected');
writeln (outfile);
writeln (outfile, ' chem proc   1982 mkt $ ',
  ' eff est inc inflation',
  ' capacity annual cost ');
writeln (outfile);
writeln (outfile);
for h := 1 to (max - 1) do
begin
  if not_big[h] then
  begin
    writeln (outfile, prod[h]:10, mpr[h]:12:2,
      cost inc[h]:13:2, infl[h]:11:2, cap[h]:13:4,
      tc[h]:11:1);
    num_lo := num_lo + 1;
  end;
end;
end.

```

Figure H-1 (continued)

- B As described in Section 9.2.2, when no information for smallest plant capacity exists, the value is set to 23 Gg, or the median of smallest existing capacities for the chemicals with available data.
- C When no price information exists for a specific chemical, the value is set to 46 ¢/kg, which is the weighted average of industry chemical prices in 1978, updated to 1982 dollars.
- D Annual cost data in dollars are converted to ¢/kg by dividing through by the capacity in Gg for each chemical and a conversion factor of 10,000.
- E This statement executes the rolled-through cost methodology defined earlier. Through a series of "for" loops, priorities are assigned (E1) and the individual costs of inputs are calculated (E2) and then aggregated in order to compute the effective cost increase for each subject chemical (E3).
- F This statement computes the inflation number as the change in price divided by the price times 100 for the percentage change in price. The conditions of the "if" statement limit the computer to perform the calculation only on the required data lines.
- G This long statement selects the highest-cost process for each chemical, sends information for that process to the output and aggregates the number of inflation values, or percentage price increase values, for the highest cost process in eight different ranges: 0%, 0% to 2%, 2% to 3%, 3% to 5%, 5% to 10%, 10% to 15%, 15% to 20%, and greater than 20%.
- H This final statement sends the calculated values of all processes not chosen as highest cost processes to the outfile in a different section from the highest-cost processes.

H.4 SCREENING ANALYSIS RESULTS

Printouts of the screening analysis output files are presented in Tables H-4 and H-5. Once again, the different files represent the different cases under study. The columns coded by letter are defined below:

Reasonable Worst Case Results (Table H-4)

- L Chemical number.
- M Chemical market price in cents per kilogram (¢/kg) in 1982 dollars.

Table H-4 Reasonable Worst-Case Price Impacts

L	M	N	O	P	Q
1	75.00	0.41	0.55	181.0000	750.7
2	58.00	0.68	1.17	41.0000	148.1
3	90.00	1.88	2.08	63.0000	42.7
4	106.00	2.58	2.43	9.0000	36.0
5	71.00	0.52	0.73	181.0000	35.7
6	95.00	1.01	1.07	7.0000	38.1
8	106.00	0.00	0.00	11.0000	0.0
9	121.00	0.00	0.00	11.0000	0.0
10	111.00	0.63	0.57	37.4000	0.0
11	84.00	1.58	1.89	59.0000	0.0
12	46.00	1.50	3.25	3.0000	44.9
14	77.00	0.00	0.00	195.0000	0.0
15	110.00	0.41	0.37	14.0000	35.9
16	99.00	3.27	3.30	5.0000	36.5
17	107.00	0.42	0.39	9.0000	37.4
18	72.00	0.42	0.58	9.0000	37.4
20	70.00	0.12	0.17	227.0000	0.0
21	112.00	4.65	4.15	5.0000	195.7
22	104.00	4.65	4.47	5.0000	0.0
25	156.00	0.93	0.60	11.0000	37.7
26	67.00	0.00	0.00	20.0000	0.0
27	67.00	1.50	2.23	3.0000	44.9
28	77.00	0.18	0.23	36.0000	65.0
29	29.00	0.00	0.00	23.0000	0.0
30	46.00	0.00	0.00	23.0000	0.0
32	172.00	0.74	0.43	27.0000	38.8
33	98.00	0.86	0.87	25.0000	38.7
34	70.00	2.55	3.64	2.0000	47.3
35	77.00	0.18	0.23	34.0000	61.0
36	88.00	0.21	0.24	36.0000	0.0
37	66.00	0.00	0.00	12.0000	0.0
38	38.00	0.00	0.00	23.0000	0.0
39	42.00	0.00	0.00	11.0000	0.0
40	73.00	2.94	4.03	25.0000	38.7
41	319.00	0.50	0.16	23.0000	35.9
43	37.00	0.00	0.00	5.0000	0.0
44	79.00	0.00	0.00	11.0000	0.0
45	84.00	2.90	3.45	23.0000	384.6
47	251.00	0.00	0.00	23.0000	0.0
48	53.00	1.07	2.03	34.0000	365.3
49	40.00	0.90	2.24	136.0000	0.0
50	44.00	0.00	0.00	11.0000	0.0
51	44.00	3.51	7.98	11.0000	364.5
52	92.00	4.17	4.53	9.0000	374.9

Table H-4 Continued.

L	M	N	O	P	Q
53	181.00	0.37	0.20	100.0000	368.6
54	174.00	3.23	1.86	45.0000	409.2
55	46.00	0.00	0.00	23.0000	0.0
56	126.00	0.00	0.00	53.0000	0.0
58	55.00	1.39	2.53	35.0000	0.0
60	121.00	1.31	1.08	45.0000	0.0
61	137.00	1.67	1.22	23.0000	0.0
62	132.00	2.11	1.60	9.0000	53.4
63	98.00	2.61	2.66	37.4000	0.0
65	120.00	0.29	0.25	23.0000	67.8
66	84.00	1.66	1.97	23.0000	381.1
68	101.00	5.19	5.14	23.0000	615.1
69	101.00	1.66	1.64	23.0000	381.1
70	163.00	0.00	0.00	23.0000	0.0
71	462.00	0.00	0.00	23.0000	0.0
72	31.00	0.54	1.75	68.0000	369.6
73	61.00	11.72	19.21	45.0000	365.2
74	157.00	0.00	0.00	23.0000	0.0
75	53.00	0.00	0.00	27.0000	0.0
77	218.00	1.67	0.76	27.0000	37.0
78	205.00	2.03	0.99	18.0000	0.0
79	46.00	0.00	0.00	23.0000	0.0
80	51.00	0.00	0.00	11.0000	0.0
81	77.00	0.00	0.00	79.0000	0.0
82	64.00	0.00	0.00	27.0000	0.0
85	33.00	0.00	0.00	8.0000	0.0
86	101.00	0.73	0.72	18.0000	36.4
87	101.00	0.56	0.56	102.0000	41.5
88	106.00	2.58	2.44	14.0000	285.5
89	93.00	1.81	1.94	23.0000	0.0
91	73.00	0.63	0.86	23.0000	0.0
92	97.00	0.75	0.78	1.0000	0.0
93	57.00	0.00	0.00	75.0000	0.0
94	53.00	0.00	0.00	45.0000	0.0
95	149.00	1.08	0.73	32.5000	0.0
96	77.00	1.87	2.43	54.0000	176.1
97	93.00	0.62	0.67	23.0000	38.5
98	115.00	1.21	1.05	9.0000	37.4
99	71.00	1.36	1.92	16.0000	36.3
102	88.00	0.22	0.25	25.0000	0.0
103	111.00	0.46	0.41	27.0000	37.0
105	139.00	1.21	0.87	25.0000	83.0
106	121.00	0.00	0.00	5.0000	0.0
108	20.00	0.35	1.73	27.0000	0.0
109	99.00	1.99	2.01	5.0000	0.0
110	101.00	0.76	0.75	5.0000	38.1
111	42.00	0.00	0.00	5.0000	0.0
112	34.00	0.00	0.00	14.0000	0.0

Table H-4 Continued.

L	M	N	O	P	Q
114	190.00	1.94	1.02	159.0000	0.0
115	40.00	0.00	0.00	27.0000	0.0
116	92.00	1.69	1.84	23.0000	38.8
117	181.00	1.48	0.82	9.0000	37.4
118	100.00	1.64	1.64	23.0000	129.5
119	132.00	2.32	1.76	14.0000	173.1
122	19.00	0.00	0.00	23.0000	0.0
123	112.00	2.66	2.37	25.0000	38.7
124	46.00	1.49	3.23	23.0000	0.0
125	181.00	0.00	0.00	11.0000	0.0
126	106.00	0.74	0.69	159.0000	0.0
127	77.00	0.00	0.00	36.0000	0.0
128	83.00	0.00	0.00	23.0000	0.0
129	84.00	0.35	0.42	23.0000	38.5
130	114.00	0.31	0.27	113.4000	0.0
132	46.00	0.00	0.00	23.0000	0.0
133	24.00	0.29	1.21	174.0000	505.3
135	269.00	0.00	0.00	27.0000	0.0
136	165.00	1.12	0.68	23.0000	43.7
137	100.00	2.31	2.31	23.0000	43.7
138	53.00	0.35	0.65	23.0000	79.7
139	71.00	0.00	0.00	5.0000	0.0
140	46.00	0.00	0.00	2.3000	0.0
141	46.00	0.00	0.00	23.0000	0.0
142	201.00	0.62	0.31	17.0000	105.0
143	196.00	0.59	0.30	34.0000	201.6
144	53.00	1.08	2.03	54.0000	0.0
145	134.00	2.05	1.53	45.0000	0.0
146	99.00	0.08	0.09	200.0000	169.6
148	108.00	3.75	3.47	7.0000	38.5
149	46.00	0.86	1.87	2.3000	0.0
150	95.00	0.61	0.64	7.0000	42.5
151	22.00	0.00	0.00	23.0000	0.0
152	66.00	0.74	1.12	7.0000	38.5
153	159.00	1.60	1.01	2.3000	36.9
154	15.00	0.00	0.00	7.0000	0.0
156	137.00	1.62	1.18	54.0000	49.7
157	260.00	0.53	0.21	127.0000	0.0
158	48.00	0.00	0.00	34.0000	0.0
159	108.00	0.78	0.72	127.0000	0.0
160	75.00	1.08	1.44	34.0000	35.8
161	84.00	0.25	0.30	21.5000	54.1
162	37.00	0.00	0.00	11.0000	0.0
163	112.00	0.71	0.63	5.0000	0.0
164	114.00	0.84	0.74	25.0000	0.0
165	97.00	0.00	0.00	11.0000	0.0
166	108.00	0.00	0.00	23.0000	0.0
168	70.00	0.84	1.20	50.0000	418.5

Table H-4 Continued..

L	M	N	O	P	Q
169	70.00	0.70	1.00	2.0000	0.0
171	100.00	0.00	0.00	23.0000	0.0
172	46.00	0.00	0.00	27.0000	0.0
173	79.00	1.54	1.95	34.0000	0.0
174	100.00	2.94	2.94	18.0000	214.8
175	79.00	0.25	0.32	21.5000	54.1
176	22.00	0.00	0.00	23.0000	0.0
177	97.00	0.07	0.07	23.0000	0.0
179	176.00	0.42	0.24	18.0000	0.0
181	92.00	0.51	0.55	29.0000	45.2
182	73.00	0.23	0.32	23.0000	53.2
183	66.00	2.48	3.76	25.0000	0.0
184	46.00	0.00	0.00	32.5000	0.0
185	99.00	0.00	0.00	113.0000	0.0
186	115.00	0.00	0.00	18.0000	0.0
187	150.00	1.90	1.26	9.0000	37.4
188	123.00	0.55	0.45	9.0000	49.7
189	91.00	1.41	1.55	227.0000	50.8
194	46.00	0.00	0.00	23.0000	0.0
195	42.00	0.00	0.00	4.0000	0.0
196	606.00	1.38	0.23	36.0000	37.5
197	91.00	3.20	3.52	23.0000	67.8
198	225.00	1.27	0.56	23.0000	67.8
199	364.00	0.92	0.25	27.0000	37.0
202	100.00	2.33	2.33	23.0000	381.1
203	77.00	8.55	11.11	91.0000	0.0
204	75.00	7.90	10.54	5.0000	373.1
205	68.00	1.08	1.59	54.0000	367.7
206	141.00	0.00	0.00	23.0000	0.0
207	68.00	0.00	0.00	16.0000	0.0
208	319.00	7.46	2.34	5.0000	372.9
209	194.00	0.00	0.00	5.0000	0.0
213	46.00	0.46	0.00	23.0000	0.0
214	46.00	0.64	0.00	23.0000	0.0
215	46.00	0.58	0.00	23.0000	0.0
216	112.00	1.35	1.20	4.0000	35.6
220	115.00	0.30	0.27	37.4000	0.0
222	101.00	4.19	4.14	5.0000	45.7
237	40.00	0.10	0.26	25.0000	0.0
238	121.00	0.00	0.00	11.5000	0.0
239	100.00	1.82	1.82	23.0000	67.8
240	123.00	19.06	15.50	2.0000	371.8
248	46.00	0.00	0.00	23.0000	0.0
249	46.00	0.00	0.00	23.0000	0.0
250	46.00	0.00	0.00	23.0000	0.0
251	46.00	0.16	0.00	23.0000	0.0
252	46.00	0.00	0.00	23.0000	0.0
254	46.00	0.00	0.00	23.0000	0.0
257	46.00	0.00	0.00	23.0000	0.0

Table H-4 Continued.

		no.	percent
chemicals having 0% inflation	=	67	35.45
chemicals having 0.1 to 1.9% inflation	=	87	46.03
chemicals having 2.0 to 2.9% inflation	=	16	8.47
chemicals having 3.0 to 4.9% inflation	=	13	6.88
chemicals having 5.0 to 9.9% inflation	=	2	1.06
chemicals having 10.0 to 14.9% inflation	=	2	1.06
chemicals having 15.0 to 19.9% inflation	=	2	1.06
chemicals having 20% or more inflation	=	0	0.00

- N Effective cost increase in €/kg. The change in price from the regulation, calculated by the rolled-through cost methodology.
- O Inflation. The percentage change in price from the regulation, calculated as the effective cost increase divided by the market price and multiplied by 100.
- P Capacity in gigagrams. This is the smallest existing plant size for the reasonable worst case.
- Q Control cost. The annual control cost under the reasonable worst-case scenario transferred from the input file, in thousands of 1982 dollars.

More Likely Case Screening Results (Table H-5)

The results in Table H-5 differ from those in Table H-4 only in that more likely case costs are used to generate the cost increases and the cost units in column Q are in 1982 dollars.

H.5 QUANTITY AND DISTRIBUTIONAL IMPACTS DISCUSSION

A separate program was used to compute the quantity and distributional impacts based on the equations and assumptions discussed in Section 9.2.3. Two different input files were used, the first containing projections data for 1990, and the second containing a reproduction of the output file from the more likely case screening model. These files are printed in Tables H-6 and H-7. The results of the program, listed originally in Tables 9-24 and 9-25, are reproduced here in Tables H-8 and H-9. A coded definition of the column headings for these tables follows:

Quantity and Distributive Impacts Input File 1 (Table H-6)

- R Chemical number.
- S This number is the projected amount of production for 1990 in Gg, as given in Table 9-18.
- T This number is the projected need for capacity in 1990 in Gg, as given in Table 9-18.
- U This number is the size of the median process unit(s) built to accommodate need for capacity in 1990 in Gg, as given in Table 9-19.
- V This number is the total capacity that will be added in 1990 to accommodate need. This number is always some multiple of the median process unit size.

Table H-5 More Likely Case Price Impacts

L	M	N	O	P	Q
1	75.00	0.00	0.00	181.00	0.00
2	58.00	0.00	0.00	41.00	0.00
4	106.00	0.16	0.15	23.00	37036.00
5	71.00	0.02	0.03	193.00	35776.00
6	95.00	0.28	0.29	15.00	41256.00
9	121.00	0.00	0.00	23.00	0.00
10	111.00	0.43	0.39	11.00	0.00
11	84.00	0.04	0.04	59.00	0.00
12	46.00	0.00	0.00	3.00	0.00
15	110.00	0.00	0.00	14.00	0.00
18	72.00	0.00	0.00	2.00	0.00
21	112.00	0.00	0.00	4.00	0.00
22	104.00	0.00	0.00	5.00	0.00
28	77.00	0.00	0.00	36.00	0.00
29	29.00	0.00	0.00	23.00	0.00
34	70.00	0.00	0.00	2.00	0.00
40	73.00	0.34	0.47	23.00	0.00
43	37.00	0.00	0.00	5.00	0.00
45	84.00	0.61	0.72	68.00	411492.00
51	44.00	0.00	0.00	11.00	0.00
52	92.00	1.07	1.17	36.00	386904.00
54	174.00	2.61	1.50	18.00	381820.00
55	46.00	0.00	0.00	23.00	0.00
58	55.00	0.00	0.00	35.00	0.00
61	137.00	0.00	0.00	23.00	0.00
65	120.00	0.34	0.28	18.00	61270.00
70	163.00	0.00	0.00	23.00	0.00
72	31.00	0.00	0.00	68.00	0.00
73	61.00	1.20	1.97	45.00	0.00
77	218.00	0.22	0.10	18.00	36392.00
85	33.00	0.00	0.00	8.00	0.00
86	101.00	0.00	0.00	18.00	0.00
87	101.00	0.00	0.00	16.00	0.00
88	106.00	0.00	0.00	18.00	0.00
89	93.00	0.00	0.00	23.00	0.00
91	73.00	0.43	0.59	23.00	0.00
92	97.00	0.52	0.53	1.00	0.00
93	57.00	0.00	0.00	75.00	0.00
94	53.00	0.00	0.00	45.00	0.00
96	77.00	0.02	0.03	54.00	0.00
97	93.00	0.31	0.33	23.00	0.00
99	71.00	0.02	0.02	318.00	56332.00
105	139.00	0.01	0.01	23.00	0.00
106	121.00	0.00	0.00	5.00	0.00
119	132.00	0.17	0.13	236.00	396356.00
122	19.00	0.00	0.00	23.00	0.00
123	112.00	0.51	0.46	7.00	35780.00
126	106.00	0.51	0.48	23.00	0.00

Table H-5 Continued.

L	M	N	O	P	Q
127	77.00	0.00	0.00	36.00	0.00
128	83.00	0.00	0.00	23.00	0.00
129	84.00	0.13	0.15	23.00	0.00
132	46.00	0.00	0.00	23.00	0.00
133	24.00	0.00	0.00	174.00	0.00
135	269.00	0.00	0.00	23.00	0.00
136	165.00	0.53	0.32	23.00	0.00
137	100.00	1.20	1.20	23.00	0.00
142	201.00	0.62	0.31	17.00	105019.00
143	196.00	0.34	0.17	80.00	269986.00
144	53.00	0.00	0.00	54.00	0.00
146	99.00	0.05	0.05	322.00	172896.00
149	46.00	0.00	0.00	5.00	0.00
151	22.00	0.00	0.00	23.00	0.00
153	159.00	0.78	0.49	5.00	38832.00
154	15.00	0.00	0.00	7.00	0.00
156	137.00	0.06	0.05	95.00	59394.00
158	48.00	0.00	0.00	34.00	0.00
159	108.00	0.54	0.50	23.00	0.00
160	75.00	0.03	0.03	153.00	39256.00
162	37.00	0.00	0.00	11.00	0.00
163	112.00	0.00	0.00	5.00	0.00
164	114.00	0.11	0.10	23.00	0.00
168	70.00	0.58	0.82	204.00	1174592.00
169	70.00	0.48	0.69	2.00	0.00
173	79.00	0.00	0.00	34.00	0.00
174	100.00	1.22	1.22	18.00	214784.00
176	22.00	0.00	0.00	23.00	0.00
177	97.00	0.04	0.04	23.00	0.00
182	73.00	0.08	0.11	206.00	169783.00
183	66.00	0.00	0.00	25.00	0.00
184	46.00	0.00	0.00	23.00	0.00
186	115.00	0.00	0.00	18.00	0.00
187	150.00	0.12	0.08	35.00	43548.00
188	123.00	0.23	0.19	43.00	99742.00
189	91.00	0.20	0.22	18.00	36392.00
194	46.00	0.00	0.00	48.00	0.00
195	42.00	0.00	0.00	41.00	0.00
204	75.00	0.87	1.16	45.00	390885.00
206	141.00	0.00	0.00	23.00	0.00
208	319.00	2.10	0.66	18.00	378900.00
209	194.00	0.00	0.00	5.00	0.00
239	100.00	1.03	1.03	23.00	67840.00
248	46.00	0.00	0.00	23.00	0.00
250	46.00	0.00	0.00	23.00	0.00
252	46.00	0.00	0.00	23.00	0.00
257	46.00	0.00	0.00	23.00	0.00

Table H-5 More Likely Case Price Impacts

number of chemicals having 0% inflation	=	52
number of chemicals having 0 to 0.9% inflation	=	36
number of chemicals having 1 to 1.9% inflation	=	7
number of chemicals having 2 to 2.9% inflation	=	0
number of chemicals having 3 to 4.9% inflation	=	0
number of chemicals having 5% or more inflation	=	0

Table H-6 Quantity and Distributive Impacts Input File 1

R	S	T	U	V
4	71	7	23	23
5	1209	744	193	772
6	127	47	15	60
45	143	10	68	68
52	69	17	36	36
54	52	3	18	18
65	52	13	18	18
77	52	7	18	18
99	4843	2345	318	2544
119	719	259	236	472
123	26	15	7	21
142	52	8	17	17
143	324	63	80	80
146	1389	623	322	644
153	481	40	5	40
156	590	304	95	380
160	600	119	153	153
168	2661	541	204	612
174	52	8	18	18
182	987	80	206	206
187	118	5	35	35
188	167	53	40	80
189	52	9	18	18
204	116	30	45	45
208	52	3	18	18
239	52	8	11	11

Table H-7 Quantity and Distributive Impacts Input File 2

W	X	Y	Z	AA
4	106.00	0.16	0.15	37036.0
5	71.00	0.02	0.03	35776.0
6	95.00	0.28	0.29	41256.0
45	84.00	0.61	0.72	411492.0
52	92.00	1.07	1.17	386904.0
54	174.00	2.61	1.50	381820.0
65	120.00	0.34	0.28	61270.0
77	218.00	0.22	0.10	36392.0
99	71.00	0.02	0.02	56332.0
119	132.00	0.17	0.13	396356.0
123	112.00	0.51	0.46	35780.0
142	201.00	0.62	0.31	105019.0
143	196.00	0.34	0.17	269986.0
146	99.00	0.05	0.05	172896.0
153	159.00	0.78	0.49	38832.0
156	137.00	0.06	0.05	59394.0
160	75.00	0.03	0.03	39256.0
168	70.00	0.58	0.82	1174592.0
174	100.00	1.22	1.22	214784.0
182	73.00	0.08	0.11	169783.0
187	150.00	0.12	0.08	43548.0
188	123.00	0.23	0.19	99742.0
189	91.00	0.20	0.22	36392.0
204	75.00	0.87	1.16	390885.0
208	319.00	2.10	0.66	378900.0
239	100.00	1.03	1.03	67840.0

Quantity and Distributive Impacts Input File 2 (Table H-7)

- W Chemical number.
- X This number is the market price in cents per kilogram ($\$/\text{kg}$). This is the price variable (P) from the discussion in Section 9.2.3.
- Y Effective cost increase in $\$/\text{kg}$. This is the change in price variable (ΔP) from the discussion in Section 9.2.3.
- Z Inflation. This is calculated as $\Delta P/P$ times 100 to get the percentage change in price from regulation.
- AA Dollar cost of the regulation for the median plant size in 1982 dollars.

Quantity Impacts Results (Table H-8)

- BB Chemical number.
- CC This number is the projected amount of production in 1990 in Gg.
- DD This number is the rolled-through change in price from the regulation in $\$/\text{kg}$ and is simply transferred from the input file to the output file by the program.
- EE This is the price variable in $\$/\text{kg}$, transferred from the input file to the output file.
- FF This is the quantity impact in Gg. This is the ΔQ variable from the discussion in Section 9.2.3 and is calculated using equation 9-2.

Distributive Impacts Results (Table H-9)

- GG Chemical number.
- HH This number is the estimation of production from existing producers in 1990 in Gg. This number is calculated by subtracting from the projection of total production in 1990, the estimated production from the process units projected to be built between 1985 and 1990.
- II This number is the direct change in price from the regulation in dollars per gigagram ($\$/\text{Gg}$). It is calculated by dividing the control cost (column AA, Table H-7) by the capacity of the median size process unit. This calculation assumes that the new process units will pass along the control cost throughout their productive capacity in the form of a price increase.

Table H-8 Quantity Impacts Output File

BB	CC	DD	EE	FF
4	71	0.16	106.00	0.08
5	1209	0.02	71.00	0.24
6	127	0.28	95.00	0.26
45	143	0.61	84.00	0.73
52	69	1.07	92.00	0.56
54	52	2.61	174.00	0.55
65	52	0.34	120.00	0.10
77	52	0.22	218.00	0.04
99	4843	0.02	71.00	0.95
119	719	0.17	132.00	0.65
123	26	0.51	112.00	0.08
142	52	0.62	201.00	0.11
143	324	0.34	196.00	0.39
146	1389	0.05	99.00	0.49
153	481	0.78	159.00	1.65
156	590	0.06	137.00	0.18
160	600	0.03	75.00	0.17
168	2661	0.58	70.00	15.43
174	52	1.22	100.00	0.44
182	987	0.08	73.00	0.76
187	118	0.12	150.00	0.07
188	167	0.23	123.00	0.22
189	52	0.20	91.00	0.08
204	116	0.87	75.00	0.94
208	52	2.10	319.00	0.24
239	52	1.03	100.00	0.37

Table H-9 Distributive Impacts Output File

GG	HH	II	JJ
4	51.5	1610.26	82847.9
5	552.8	185.37	102471.4
6	76.0	2750.40	209030.4
45	85.2	6051.35	515575.3
52	38.4	10747.33	412697.6
54	36.7	21212.22	778488.6
65	36.7	3403.89	124922.7
77	36.7	2021.78	74199.2
99	2680.6	177.14	474854.0
119	317.8	1679.47	533737.0
123	8.2	5111.43	41658.1
142	37.5	6177.59	231968.4
143	256.0	3374.82	863955.2
146	841.6	536.94	451892.2
153	447.0	7766.40	3471580.8
156	267.0	625.20	166928.4
160	469.9	256.58	120577.5
168	2140.8	5757.80	12326306.6
174	36.7	11932.44	437920.7
182	811.9	824.19	669159.3
187	88.3	1244.23	109803.2
188	99.0	2493.55	246861.4
189	36.7	2021.78	74199.2
204	77.8	8686.33	675362.4
208	36.7	21050.00	772535.0
239	42.7	6167.27	263034.2

JJ This number is the distributional impact given in dollars.
It is calculated by multiplying the direct change in price by
the production in 1990 from existing facilities.

H.6 PROCESS ROUTES

Figure H-2 describes the maximum cost production process routes selected by the screening model for all 173 reactor processes chemicals and for all intermediate chemicals.

For each chemical, the figure shows the chemical ID number in the middle of the page, and its common name on the right side (see Table H-1). On the left side are the input or inputs that are used to make each chemical. In two cases there are three inputs that combine to form a chemical, but most often there are only one or two. An example of the process route figure will illustrate what each of the elements represents.

Example 1 -

1.00	0.50	1.75		
xx ---->	yy ---->	zz ---->	ID	Name
	1.10	0.90		
	x ---->	y ---->		

Chemicals zz and y are the direct inputs into chemical ID. Chemicals xx and yy, and x, are upstream inputs in the production of chemicals zz and y, respectively. The numbers above each input line (---->) represent the input ratio units of the preceding chemical into the one that follows. The input ratio kilogram is the amount of input chemical needed to produce 1 unit of the chemical produced. For example, 1.75 units of chemical zz when combined with 0.90 units of chemical y will form 1 unit of chemical ID.

In Figure H-2, as in this example, inputs are traced upstream for up to three stages. For most chemicals the upstream process route has no more than three stages. In a few cases there are further chemicals upstream that feed into the initial chemical, which is xx in the example route. Chemicals that have more than three process stages are footnoted with an asterisk. To find the remaining upstream process stages, locate the process route for the chemical next to the asterisk.

As in other listings, the chemicals are ordered by ID number ranging from 1 to 257. There are several missing numbers. These numbers have either not been assigned to a chemical or have been assigned to a chemical that is not produced by reactor processes or is not an intermediate in the production of a reactor process chemical.

Process Route	Chemical ID	Common Name
0.71 94----->	1	ACETALDEHYDE
0.71 0.77 94-----> 1----->	2	ACETIC ACID
0.71' 0.77 1.40 94-----> 1-----> 2----->	3	ACETIC ANHYDRIDE
0.77 1.59 0.79 * 1-----> 2-----> 95----->		
0.71 0.77 0.54 94-----> 1-----> 2----->	4	N-BUTYL ACETATE
0.75 1.03 0.71 184-----> 28-----> 34----->		
0.71 0.77 0.73 94-----> 1-----> 2----->	5	VINYL ACETATE
0.37 94----->		
0.71 0.77 0.69 94-----> 1-----> 2----->	6	ETHYL ACETATE
0.61 0.59 94-----> 93----->		
1.18 94----->	8	ALCOHOLS, C-11 OR LOWER, MIXTURES
1.29 94----->	9	ALCOHOLS, C-12 OR HIGHER, MIXTURES
1.00 0.75 94-----> 168----->	10	ETHANOLAMINE
0.65 1.47 12-----> 160----->	11	ANILINE

Figure H-2 Production Process Routes

Process Route	Chemical ID	Common Name
no inputs for chemical #	12	BENZENE
5.56 0.67 79-----> 82----->	14	TEREPHTHALIC ACID
4.55 0.98 0.39 79-----> 80-----> 127-----> 0.75 1.23 0.70 184-----> 28-----> 102----->	15	DIOCTYL PHTHALATE
0.75 1.03 0.26 184-----> 28-----> 34-----> 0.80 0.45 135-----> 52-----> 4.55 0.98 0.53 79-----> 80-----> 127----->	16	BUTYLBENZYL PHTHALATE
1.29 1.18 94-----> 9-----> 4.55 0.98 0.29 79-----> 80-----> 127----->	17	DI-N-HEPTYL-N-NONYL UNDECYL PHTHALATE
4.55 0.98 0.34 79-----> 80-----> 127-----> 1.21 1.25 0.75 184-----> 162-----> 128----->	18	DIISODECYL PHTHALATE
5.56 0.61 79-----> 82-----> 0.56 0.40 132-----> 133----->	20	DIMETHYLTEREPHTHALATE
0.49 12----->	21	BENZENESULFONIC ACID

Figure H-2 Production Process Routes

Process Route	Chemical ID	Common Name
0.49 1.00 12-----> 21----->	22	BENZENESULFONIC ACID, MONO-C10-16-ALKYL DERIVATIVES, SODIUM SALTS
0.71 0.40 94-----> 1----->	25	PENTAERYTHRITOL
0.56 1.19 1.22 132----->133----->108----->		
1.93 29----->	26	BIVINYL
1.35 39----->	26	BIVINYL
1.80 29----->	27	BUTADIENE and BUTENE FRACTIONS
0.75 184----->	28	BUTYRALDEHYDE
no inputs for chemical #	29	N-BUTANE
no inputs for chemical #	30	BUTANES, MIXED
1.19 41----->	32	1,4-BUTANEDIOL
0.75 0.91 1.24 184-----> 28----->251----->	33	BUTYRIC ANHYDRIDE
0.77 1.59 0.30 1-----> 2-----> 95----->		
0.75 1.03 184-----> 28----->	34	N-BUTYL ALCOHOL

Figure H-2 Production Process Routes
H-47

Process Route	Chemical PD	Common Name
1.00 0.90 94----> 37---->	35	SEC-BUTYL ALCOHOL
1.00 0.90 1.17 94----> 37----> 35---->	36	METHYL ETHYL KETONE
1.00 94---->	37	A-BUTYLENE
1.00 1.15 94----> 37---->	38	B-BUTYLENE
no inputs for chemical #	39	BUTYLENES (MIXED)
0.75 1.03 0.90 184----> 28----> 34----> 1.00 0.59 94----> 168---->	40	BUTYL CELLUSOLVE
2.82 0.43 176----> 106----> 0.56 1.19 1.00 132----> 133----> 108---->	41	2-BUTYNE-1,4-DIOL
1.00 1.00 132----> 248---->	42	CARBAMIC ACID MONOAMMONIUM SALT
0.23 132---->	43	CARBON DISULFIDE
1.00 1.00 132----> 249---->	44	PHOSGENE
0.82 12---->	45	CHLOROBENZENE, MONOMER
0.33 0.43 1.10 132----> 50----> 207---->	47	FREON 22

Figure H-2 Production Process Routes
H-48

Process Route	Chemical ID	Common Name
0.61 0.75 94-----> 93----->	48	ETHYL CHLORIDE
0.31 1.65 94-----> 72----->	49	VINYL CHLORIDE
0.33 132----->	51	METHYL CHLORIDE
0.56 0.68 132-----> 133----->	51	METHYL CHLORIDE
0.80 135----->	52	BENZYL CHLORIDE
0.74 1.08 184-----> 56----->	53	EPICHLOROHYDRIN
0.82 0.80 12-----> 45----->	54	P-CHLORONITROBENZENE
0.64 184----->	55	PROPYLENE CHLOROHYDRIN
0.74 184----->	56	ALLYL CHLORIDE
0.93 12----->	58	CYCLOHEXANE
0.93 0.94 12-----> 58----->	50	CYCLOHEXANE, OXIDIZED
0.93 1.20 12-----> 58----->	61	CYCLOHEXANOL
0.93 1.20 0.84 12-----> 58-----> 61----->	62	CYCLOHEXANONE

Figure H-2 .Production Process Routes
H-49

Process Route	Chemical ID	Common Name
1.20 0.84 1.24 * 58----> 61----> 62---->	63	CYCLOHEXANONE OXIME
1.00 1.00 176----> 250---->	65	TRIMETHYLENE
0.17 94---->	66	ETHYLENE DIBROMIDE
1.93 0.94 1.52 29----> 26----> 69---->	68	1,4-DICHLOROBUTENE
1.93 0.94 29----> 26---->	69	3,4-DICHLORO-1-BUTENE
0.11 1.33 132----> 195---->	70	FREON 12
0.33 1.12 132----> 50---->	71	DIMETHYLDICHLOROSILANE
0.31 94---->	72	ETHYLENE DICHLORIDE
0.31 0.81 1.38 94----> 72----> 204---->	73	VINYLDENE CHLORIDE
0.33 0.43 1.45 132----> 50----> 207---->	74	FREON 21
0.33 0.61 132----> 50---->	75	METHYLENE CHLORIDE
0.30 94---->	77	DIETHYLBENZENE
1.12 99---->		

Figure H-2 Production Process Routes
H-50

Process Route	Chemical ID	Common Name
1.00 1.00 1.43 132----->249-----> 44----->	78	TOLUENE-2,4-(and 2,6)- DIISOCYANATE (80/20 MIXTURE)
0.53 3.57 0.88 135----->143----->137----->		
no inputs for chemical #	79	XYLENES (MIXED)
4.55 79----->	80	O-XYLENE
2.50 79----->	81	M-XYLENE
5.56 79----->	82	P-XYLENE
1.27 184----->	85	DODECENE
0.35 12----->	86	DODECYLBENZENE, LINEAR
1.27 0.76 184-----> 85----->		
0.35 12----->	87	DODECYLBENZENE, NONLINEAR
1.27 0.76 184-----> 85----->		
0.75 86----->	88	DODECYLBENZENESULFONIC ACID
0.75 0.70 86-----> 88----->	89	DODECYLBENZENESULFONIC ACID SODIUM SALT
1.00 0.75 94----->168----->	91	ETHYLENE GLYCOL

Figure H-2 Production Process Routes
H-51

Process Route	Chemical ID	Common Name
1.00 0.90 94---->168---->	92	TRIETHYLENE GLYCOL
0.61 94---->	93	ETHYL ALCOHOL
no inputs for chemical #	94	ETHYLENE
0.71 0.77 1.59 94----> 1----> 2---->	95	KETENE
1.13 99---->	96	STYRENE
0.61 0.57 94----> 93---->	97	ETHYLENE GLYCOL MONOETHYL ETHER
1.00 0.54 94---->168---->		
0.71 0.77 0.48 94----> 1----> 2---->	98	ETHYLENE GLYCOL MONOETHYL ETHER ACETATE
0.76 97---->		
0.76 12---->	99	ETHYLBENZENE
0.28 94---->		
0.75 1.23 184----> 28---->	102	2-ETHYLHEXYL ALCOHOL
0.75 1.23 1.44 184----> 28---->102---->	103	(2-ETHYLHEXYL) AMINE
0.64 99---->	105	6-ETHYL-1,2,3,4-TETRAHYDRO- 9-10-ANTHRACENEDIONE
4.55 0.98 0.90 79----> 80---->127---->		

Figure H-2 Production Process Routes
H-52

Process Route	Chemical ID	Common Name
2.82 176----->	106	ACETYLENE
4.10 132----->	106	ACETYLENE
0.56 1.19 132----->133----->	108	FORMALDEHYDE
1.33 12----->	109	MALEIC ANHYDRIDE
no inputs for chemical #	110	SORBITOL
no inputs for chemical #	111	N-HEPTANE
0.79 39----->	112	HEPTENES (MIXED)
1.70 184----->	112	HEPTENES (MIXED)
1.20 0.84 0.92 58-----> 61-----> 62----->	114	CAPROLACTAM
no inputs for chemical #	115	HEXANE
1.80 0.72 0.93 29-----> 27----->118----->	116	1,6-HEXANEDIAMINE
0.72 0.93 0.63 * 27----->118----->116----->	117	1,6-HEXANEDIAMINE ADIPATE
0.80 120----->		

Figure H-2 Production Process Routes
H-53

Process Route	Chemical ID	Common Name
1.80 0.72 29-----> 27----->	118	ADIPONITRILE
0.93 0.78 12-----> 58----->	119	ADIPIC ACID
0.79 132----->	122	HYDROCYANIC ACID
2.30 1.01 144----->183----->	123	DIACETONE ALCOHOL
2.30 0.60 144----->183----->	124	ACETONE CYANOHYDRIN
no inputs for chemical #	125	CITRIC ACID
1.00 0.88 94----->168----->	126	DIETHANOLAMINE
4.55 0.98 79-----> 80----->	127	PHTHALIC ANHYDRIDE
1.21 1.25 184----->162----->	128	ISODECYL ALCOHOL
1.29 0.93 94-----> 9----->	129	LINEAR ALCOHOLS, ETHOXYLATED, MIXED
1.00 0.22 94----->168----->		
0.87 129----->	130	LINEAR ALCOHOLS, ETHOXYLATED and SULFATED, SODIUM SALT MIXED
no inputs for chemical #	132	METHANE
0.56 132----->	133	METHANOL

Figure H-2 Production Process Routes

Process Route	Chemical ID	Common Name
no inputs for chemical #	135	TOLUENE
0.53 1.57 135----->143----->	136	TOLUENE-2,2-DIAMINE
0.53 3.57 135----->143----->	137	ar-METHYLBENZENEDIAMINE
1.30 141----->	138	ISOPRENE
no inputs for chemical #	139	ISOPENTANE
no inputs for chemical #	140	AMYLENE
no inputs for chemical #	141	AMYLENES, MIXED
0.53 135----->	142	2,4-(and 2,6)-DINITROTOLUENE
0.53 135----->	143	2,4-DINITROTOLUENE
0.72 12----->	144	CUMENE
1.17 184----->		
0.80 1.79 0.88 * 144----->149----->173----->	145	BISPHENOL A
2.30 0.28 144----->183----->		
0.64 1.47 184-----> 55----->	146	PROPYLENE OXIDE

Figure H-2 Production Process Routes

H-55

Process Route	Chemical ID	Common Name
2.30 1.29 144----->183----->	148	2-METHYLPENTANE
0.80 144----->	149	CUMENE HYDROPEROXIDE
0.75 184----->	150	ISOBUTYRALDEHYDE
1.15 29----->	151	ISOBUTANE
0.75 1.03 184-----> 28----->	152	ISOBUTYL ALCOHOL
0.92 154----->	153	tert-BUTYL ALCOHOL
no inputs for chemical #	154	ISOBUTYLENE
0.79 0.27 132----->122----->	156	METHYL METHACRYLATE
0.56 0.32 132----->133----->		
2.30 0.58 144----->183----->		
1.19 0.72 41-----> 32----->	157	1-METHYL-2-PYRROLIDONE
no inputs for chemical #	158	NAPTHENE
1.00 0.93 94----->168----->	159	TRIETHANOLAMINE
0.65 12----->	160	NITROBENZENE

Figure H-2 Production Process Routes
H-56

Process Route	Chemical ID	Common Name
254-----> 1.00	161	NONYL ALCOHOL
184-----> 1.21	162	TRIPROPYLENE
184-----> 1.21 0.76 162----->	163	NONYLPHENOL
* 144-----> 0.80 1.79 0.46 149-----> 173----->		
163-----> 0.96 94-----> 1.00 0.19 168----->	164	NONYLPHENOL, ETHOXYLATED
39-----> 1.00		
no inputs for chemical #	165	OCTENE
94-----> 1.00	166	OIL SOLUBLE PETROLEUM SULFONATE
94-----> 1.00	168	ETHYLENE OXIDE
94-----> 1.00 0.84 168----->	169	DIETHYLENE GLYCOL
29-----> 1.93 0.96 26----->	171	3-PENTENENITRILE
no inputs for chemical #	172	PENTENES, MIXED
144-----> 0.80 1.79 149----->	173	PHENOL
99-----> 1.28	174	1-PHENYLETHYL HYDROPEROXIDE

Figure H-2 Production Process Routes
H-57

Process Route	Chemical ID	Common Name
0.60 94----->	175	PROPANAL
no inputs for chemical #	176	PROPANE
0.64 1.47 0.77 184-----> 55-----> 146----->	177	PROPYLENE GLYCOL
0.74 1.08 1.15 184-----> 56-----> 53----->	179	GLYCEROL
0.60 1.40 94-----> 175----->	181	PROPYL ALCOHOL
0.85 184----->	182	ISOPROPYL ALCOHOL
2.30 144----->	183	ACETONE
no inputs for chemical #	184	PROPYLENE
1.25 184----->	185	ACRYLONITRILE
0.83 184----->	186	ACRYLIC ACID
0.75 1.03 0.58 184-----> 28-----> 34-----> 0.83 0.57 184-----> 186----->	187	BUTYL ACRYLATE
0.61 0.48 94-----> 93-----> 2.82 0.32 176-----> 106----->	188	ETHYL ACRYLATE

Figure H-2 Production Process Routes
H-58

Process	Route	Chemical	ID	Common	Name
	0.93 12----->	189		PHENYLPROPANE	
	0.50 184----->				
	0.21 132----->	194		PERCHLOROETHYLENE	
	0.11 132----->	195		CARBON TETRACHLORIDE	
0.61 94----->	0.75 93----->	1.19 48----->	196	TETRAETHYL LEAD	
0.93 12----->	1.20 58----->	1.74 61----->	197	CYCLAHEXANE	
	1.19 41----->	1.31 32----->	198	TETRAHYDROFURAN	
0.61 94----->	0.75 93----->	0.73 48----->	199	TETRA (METHYL-ETHYL) LEAD	
	0.33 132----->	1.14 50----->	200	TETRAMETHYL LEAD	
	2.30 144----->	0.27 183----->	202	BROMETONE	
0.81 *72----->	1.38 204----->	0.73 73----->	203	METHYL CHLOROFORM	
	0.31 94----->	0.81 72----->	204	VINYL TRICHLORIDE	
	0.31 94----->	0.74 72----->	205	TRICHLOROETHYLENE	

Figure H-2 Production Process Routes
H-59

Process Route	Chemical ID	Common Name
0.11 1.17 132----->195----->	206	FREON 11
0.33 0.43 132-----> 50----->	207	CHLOROFORM
0.79 1.00 1.00 132----->122----->257----->	208	CYANURIC CHLORIDE
0.21 0.98 132----->194----->	209	FLOUROCARBON 113
0.71 1.11 94-----> 1----->	213	ACETALDOL
0.71 1.11 1.40 94-----> 1----->213----->	214	CROTONALDEHYDE
1.11 1.40 0.90 * 1----->213----->214----->	215	CROTONIC ACID
0.56 1.19 1.32 132----->133----->108----->	216	HEXAMETHYLENE TETRAAMINE
0.56 1.05 132----->133----->	220	METHYLAMINE
2.30 1.32 144----->183----->	222	MESITYL OXIDE
0.56 0.36 132----->133----->	237	METHYL tert-BUTYL ETHER
0.64 154----->		
1.29 1.00 94-----> 9----->	238	ALCOHOLS, C-12 or higher, UNMIXED

Figure H-2 Production Process Routes
H-60

Process Route	Chemical ID	Common Name
0.92 0.95 154----->153----->	239	tert-BUTYL HYDROPEROXIDE
0.71 0.77 0.69 94-----> 1-----> 2----->	240	CHLOROACETIC ACID
1.00 132----->	248	CARBON DIOXIDE
1.00 132----->	249	CARBON MONOXIDE
1.00 176----->	250	1,3 DICHLOROPROPANE
0.75 0.91 184-----> 28----->	251	BUTYRIC ACID
1.00 132----->	252	SYNTHESIS GAS
no inputs for chemical #	254	DIISOBUTENE
0.79 1.00 132----->122----->	257	CYANOGEN CHLORIDE

Figure H-2 Production Process Routes
H-61

TECHNICAL REPORT DATA (Please read Instructions on the reverse before completing)		
1. REPORT NO. EPA 450/3-90-016a	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Reactor Processes in Synthetic Organic Chemical Manufacturing - Background Information for Proposed Standards	5. REPORT DATE June 1990	6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S)	8. PERFORMING ORGANIZATION REPORT NO.	
9. PERFORMING ORGANIZATION NAME AND ADDRESS Office of Air Quality Planning and Standards U. S. Environmental Protection Agency Research Triangle Park, North Carolina 27711	10. PROGRAM ELEMENT NO.	11. CONTRACT/GRANT NO. 68-02-3816
12. SPONSORING AGENCY NAME AND ADDRESS Director, Office of Air Quality Planning and Standards Office of Air and Radiation U. S. Environmental Protection Agency Research Triangle Park, North Carolina 27711	13. TYPE OF REPORT AND PERIOD COVERED	14. SPONSORING AGENCY CODE EPA/200/04
15. SUPPLEMENTARY NOTES This report discusses the regulatory alternatives considered during the development of the proposed new source performance standards and the environmental and economic impacts associated with the regulatory alternatives.		
16. ABSTRACT Standards of performance for the control of volatile organic compound (VOC) emissions from new, modified, and reconstructed reactor process units used in the manufacture of synthetic organic chemicals are being proposed under Section 111 of the Clean Air Act. This document contains background information on the industry and processes concerned and environmental and economic impact assessments of the regulatory alternatives considered in developing the proposed standards.		
17. KEY WORDS AND DOCUMENT ANALYSIS		
a. DESCRIPTORS Air pollution Pollution control Standards of performance Volatile organic compounds Organic chemical industry	b. IDENTIFIERS/OPEN ENDED TERMS Air pollution control	c. COSATI Field/Group 138
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